OAH Dkt. No. 12-2500-17037-2
MPUC Dkt. No. ET-6131, ET-2, ET-6130,
ET-10, ET-6444, E-017, ET-9/CN-05-619

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Otter Tail Power Company and Others for Certification of Transmission Facilities in Western Minnesota

SUMMARY OF TESTIMONY RECEIVED IN RESPONSE TO REPORT OF BOSTON PACIFIC COMPANY, INC.

Pursuant to the Public Utilities Commission's August 7, 2008, Order Referring Case to the Office of Administrative Hearings for Additional Evidentiary Proceedings, additional hearings were held in this matter on November 12 and 13, 2008, at the Public Utilities Commission in St. Paul.

The following persons appeared:

Todd J. Guerrero and David L. Sasseville, Lindquist & Vennum PLLP, 80 South Eighth Street, Suite 4200 IDS Center, Minneapolis, MN 55402, and Peter S. Glaser, Troutman Sanders LLP, 401 Ninth Street, Suite 1000, Washington, DC 20004-2134, appeared on behalf of the Applicants, namely, Otter Tail Power Company, Missouri River Energy Services, Montana-Dakota Utilities, Central Minnesota Municipal Power Agency, and Heartland Consumers Power District.

Dr. Stephen R. Rakow, Rates Analyst, appeared on behalf of the Office of Energy Security (OES) of the Department of Commerce, 85 – 7th Place East, Suite 500, St. Paul, MN 55101-2198.

Elizabeth I. Goodpaster, Minnesota Center for Environmental Advocacy, 26 East Exchange Street, Suite 206, St. Paul, Minnesota 55101, appeared on behalf of the Joint Intervenors, namely, the Minnesota Center for Environmental Advocacy, Union of Concerned Citizens, the Izaak Walton League of America – Midwest Office, Fresh Energy, and Wind on the Wires.

Christopher Sandberg, Lockridge, Grindal Nauen, P.L.L.P., 100 Washington Ave. S., Suite 2200, Minneapolis, Minnesota, 55401, appeared on behalf of the Midwest Independent System Operator (Midwest ISO or MISO).

Christopher Greenman, Assistant General Counsel, Excelsior Energy, Inc., 11100 Wayzata Boulevard, Suite 305, Minnetonka, Minnesota 55305, appeared on behalf of Excelsior Energy, Inc.

The Honorable Dr. David C. Boyd, Phyllis Reha, Thomas W. Pugh, J. Dennis O'Brien, and Betsy Wergin, Commissioners; David Jacobson and Robert Cupit, staff members; and Jeanne Cochran, Assistant Attorney General, 445 Minnesota Street, Suite 1100, St. Paul, Minnesota 55101, appeared on behalf of the Minnesota Public Utilities Commission (PUC or Commission), Suite 350, 121 Seventh Place East, St. Paul, Minnesota 55101-2147.

NOTICE

This report contains a summary of testimony. It is not a final decision. Pursuant to Minn. R. 7849.5720, the Commission will make the final determination of this matter.

PROCEDURAL BACKGROUND

On October 3, 2005, the Applicants filed an application for a certificate of need and a route permit to upgrade existing transmission facilities in the western part of the state. On December 19, 2005, the PUC referred the applications to the Office of Administrative Hearings for contested case proceedings.

The Administrative Law Judges assigned to the case conducted extensive public and evidentiary hearings. The ALJs issued their initial report on August 15, 2007, concluding that the Applicants had demonstrated compliance with the criteria for issuance of a Certificate of Need under Minn. Stat. § 216B.243 and other applicable statutes and Minn. R. 7849.0120, and that the Commission should grant the Certificate of Need and Route Permits.[1] On August 31, 2007, a settlement agreement between the Department of Commerce and the Applicants ("Settlement Agreement") was filed with the Commission.

On September 18, 2007, before the PUC took action, the Applicants filed a letter stating that two of the original applicants -- Great River Energy ("GRE") and Southern Minnesota Municipal Power Agency ("SMMPA") – were withdrawing as participants in the Big Stone II generation and transmission project.[2] The Applicants concluded that the withdrawal of these two entities would not change their need for the transmission lines, but might necessitate changes in the size and design of the proposed Big Stone II generating plant.

On October 19, 2007, the PUC referred the certificate of need matter back to the Office of Administrative Hearings for further evidentiary proceedings in light of these new facts and changed circumstances. After holding an additional public hearing as well as additional evidentiary hearings, the Administrative Law Judges issued

[1] Initial ALJ Report, Recommendation, ¶ 16.
[2] App. Ex. 114 at 1 (Uggerud).

Supplemental Findings of Fact, Conclusions of Law, and Recommendation on May 9, 2008. They recommended denying the application for a Certificate of Need on the grounds that (1) the Applicants had not demonstrated under Minn. Stat. § 216B.243, subd. 3, that their demand for electricity could not be met more cost-effectively through energy conservation and load management measures; and (2) the Applicants had not demonstrated under Minn. Stat. § 216B.243, subd. 3a, that they had explored obtaining power from renewable energy sources and found that power from the proposed Big Stone II plant would be less expensive, including environmental costs. The parties filed exceptions and replies to exceptions in accordance with the Commission's rules of practice and procedure. On June 3, 2008, the Commission heard oral argument from the parties.

On June 5, 2008, the Commission met to deliberate the merits of the case. At that time, it deferred action on the case for the purposes of obtaining additional expert opinion. On August 7, 2008, the Commission issued an Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings. The order stated that three issues in this case required further development to ensure informed decision-making, in part due to post-hearing developments. Those issues were identified as follows:

> a. *Carbon Regulation Costs* – How would passage of the greenhouse-gas regulation bills introduced in Congress to date affect the cost of energy and power generated by a supercritical, pulverized-coal-fired plant such as Big Stone II? Bills introduced to date would include the 2003 McCain-Lieberman bill, the 2007 Bingaman-Specter bill, and the 2007 McCain-Lieberman bill.
>
> b. *Construction Costs* – What are the likely construction costs for a supercritical, pulverized-coal-fired plant such as Big Stone II, constructed on a brownfield site, with an in-service date around 2014-2015? What are the likely construction costs for an alternative wind generation system, with natural-gas-fired back-up, with a comparable capacity factor and in-service date? What are the likely construction costs for a natural-gas-fired plant with a comparable capacity factor and in-service date?
>
> c. *Natural Gas and Coal Costs* – What are the likely delivered costs of natural gas and coal for power plants in the North Dakota/South Dakota/Minnesota area over the first fifteen years of the operation of any of the three generation systems described above, assuming the passage of climate-change regulation?[3]

The PUC further indicated that, to expedite consideration of these issues, it would retain an expert through a Request for Proposals to analyze the issues and provide a written report detailing his or her conclusions. The Commission returned the case to the Office

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[3] Order Referring Case to Office of Administrative Hearings for Additional Evidentiary Proceedings at 3 (Aug. 7, 2008).

of Administrative Hearings for further evidentiary proceedings under the Administrative Procedure Act, Minn. Stat. § 14.001, et seq., and asked that the proceedings include the testimony of the Commission's expert, including the expert's report, rebuttal testimony as necessary, cross-examination as appropriate, and a supplemental report from the Administrative Law Judge. The Commission also asked that the evidentiary hearings be conducted as expeditiously as possible, consistent with the need for informed decision-making and the due process rights of all parties, at a time and place that would permit the Commissioners to attend and ask questions. The Order set a target date for the Administrative Law Judge's Report of 120 days from the date the expert was retained.

A request for proposals was issued by the PUC in August 2008, and Boston Pacific Company, Inc. ("Boston Pacific"), was selected to provide the expert opinion. In the past, Boston Pacific has been engaged as an independent evaluator or monitor for power procurement in several states, including Oregon, Oklahoma, Delaware, the District of Columbia, Illinois, Maryland and New Jersey. Boston Pacific staff members have served as expert witnesses on resource decisions before State Commissions and FERC and on power project development in the United States and other countries.[4]

On October 21, 2008, Boston Pacific issued its Report Responding to the Commission's Inquiries on Emissions Costs, Construction Costs, and Fuel Costs.[5] The two principal authors of the Report are Craig R. Roach, the founder of Boston Pacific, who holds a Ph.D. in Economics and has experience as an electricity and natural gas expert witness, and Frank Mossburg, who holds an MBA and a BS in Economics and has experience in analyzing utility-produced models and data.[6]

On November 6, 2008, the parties submitted written prefiled testimony in this matter. The Applicants filed the testimony of the following individuals: Marc Chupka of the Brattle Group;[7] Ward Uggerud, Senior Vice President of Otter Tail Power Company;[8] Mark Rolfes, Project Manager for Big Stone II;[9] Jeffrey Greig of Burns and McDonnell;[10] and Thomas Hewson of Energy Ventures Analysis.[11] The Joint Intervenors filed the testimony of David Schlissel of Synapse Energy Economics, Inc.[12] MISO filed the testimony of Eric Laverty, Senior Manager of Transmission Access Planning for MISO.[13]

On November 10, 2008, the Administrative Law Judge granted the motion of the Joint Intervenors to strike Mr. Laverty's prefiled testimony in its entirety, and their additional motion to strike a portion of Mr. Uggerud's testimony (Ex. 144, page 12, line

[4] ALJ Ex. 2 at 2, fn 2.
[5] ALJ Ex. 2.
[6] ALJ Ex. 2 at 38-53.
[7] Applicants' Ex. 147.
[8] Applicants' Ex. 144.
[9] Applicants' Ex. 145.
[10] Applicants' Ex. 146.
[11] Applicants' Ex. 148.
[12] Joint Intervenors' Ex. 50.
[13] MISO Ex. 3.

20, through page 13, line 14, and attachments 144A and 144B) on the grounds that the testimony exceeded the proper scope of this additional evidentiary proceeding. The Administrative Law Judge ruled that the stricken testimony would remain in the record as an offer of proof for the Commission's consideration. Additional evidentiary hearings were held at the PUC in St. Paul, Minnesota, on November 12 and November 13, 2008. The PUC Commissioners attended and had the opportunity to ask questions. Testimony from Dr. Roach and Mr. Mossburg was heard at that time, as well as additional examination and cross-examination of Mr. Uggerud, Mr. Greig, Mr. Rolfes, Mr. Hewson, Mr. Chupka, and Mr. Schlissel.

The testimony provided by those responding to the Boston Pacific Report is summarized below to facilitate the Commission's deliberations and ultimate decision in this matter. The Boston Pacific Report itself is not summarized in detail, but the major recommendations contained in the Report are included in order to provide context for the testimony. Following the hearing, written briefs were submitted by the Applicants, the OES, and the Joint Intervenors. Those briefs are not summarized in this Report.

SUMMARY OF ADDITIONAL TESTIMONY

In its Report, Boston Pacific concluded that "the range of emissions, construction, and fuel price inputs used in the Applicants' analyses were not appropriate; put another way, they were out of line with current 'best practices' resource selection methodologies."[14] In his testimony at the hearing, Dr. Roach indicated that "the primary reason for that conclusion was that we didn't feel that the Applicants tested the resource decision over a broad enough range of assumptions about the three key uncertainties."[15] He also noted that a further analytic question focuses on whether a levelized cost analysis suffices.[16] Thus, in addition to the three specific cost issues encompassed in the Report, an overarching issue during this proceeding was the sufficiency of the modeling methodology used by the Applicants and whether it appropriately assessed risks. Much of the discussion involved the updated levelized cost analysis provided by Applicants' witness Jeffrey Greig in connection with this phase of the proceeding.

The testimony of Mr. Greig and other witnesses on behalf of the Applicants on the methodology issue will first be summarized below, followed by a summary of the testimony of Boston Pacific and the Joint Intervenors on that issue. Thereafter, the testimony of the parties on carbon regulation costs, construction costs, and natural gas and coal costs will be summarized, followed by a summary of additional subjects that came up in testimony.

[14] ALJ Ex. 2 at 5.
[15] T. Vol. 1 at 12.
[16] T. Vol. 1 at 14-15.

I. Methodology/Use of Levelized Cost Modeling

A. Testimony of Applicants' Witnesses

1. Jeffrey Greig

Jeffrey Greig is the Vice President and General Manager of the Business and Technology Services Division of Burns & McDonnell, an engineering and construction firm headquartered in Kansas City, Missouri. In his rebuttal testimony, Mr. Greig provided an updated levelized cost analysis on behalf of the Applicants comparing the costs of alternative baseload resources that incorporated the results of the Boston Pacific Report. A levelized cost analysis takes various assumptions (such as capital costs, fuel costs, performance, and operating costs) into consideration and derives a single number, expressed in dollars per megawatt hour, reflecting what the cost of generation from a particular alternative would be over the expected lifetime of the project. He indicated that he used the same methodology as discussed in his prior testimony in this case, but this time reflecting the recommendations contained in the Boston Pacific report.[17]

Mr. Greig compared the economics of a supercritical pulverized coal (SCPC) unit with a comparably-sized natural gas-fired combined cycle gas turbine (CCGT) unit and a comparably sized gas-wind alternative for two different models (an investor-owned utility, and a public power utility). He testified that he treated the two types of utilities separately because they generally use different financing structures and have different revenue requirements. Because an investor-owned utility has higher costs of capital than a public power utility that can issue tax-free debt, a public power utility generally will be able to deploy capital at a lower cost than an investor-owned utility. He examined a combined cycle alternative rather than a simple cycle option because simple cycle facilities are typically used for peaking capacity and CCGTs are more efficient and lower cost when they are being run at baseload levels.[18]

Mr. Greig concluded that the results of the updated analysis were generally quite consistent with the analysis he submitted in this matter in January 2008. Mr. Greig's overall conclusions were as follows:

For investor-owned utilities:

- If the federal production tax credit (PTC) for wind <u>is not</u> extended, a 500 MW SCPC unit represents a lower cost baseload generation alternative on a life-cycle basis compared to a CCGT plus Wind case across an entire range of CO2 costs from $4 per ton to $30 per ton. The breakeven CO2 cost between the two alternatives in such a situation is approximately $37/ton, assuming the cost is applied on every ton of CO2 emissions.

[17] Applicants' Ex. 146 at 1, 3-4; T. Vol. 1 at 184-185; *see also* Applicants' Ex. 144 at 2-3 and T. Vol. 1 at 163 (Uggerud).
[18] Applicants' Ex. 146 at 1, 4; T. Vol. 1 at 213, 215-217.

§ If the PTC is extended, the breakeven CO2 cost between a 500 MW SCPC unit and the CCGT plus Wind alternative is approximately $26 per ton for an investor-owned utility.

§ The breakeven CO2 cost between a 500 MW SCPC unit compared to a CCGT plus Wind alternative, both with and without the PTC, is highly sensitive to natural gas costs. Increases in natural gas costs will increase the breakeven CO2 cost point.

For public power utilities:

§ A 500 MW SCPC unit is a lower cost baseload generation alternative across the entire $4-$30 per ton range of CO2 costs compared to the CCGT plus Wind alternative, with or without an assumed extension of the federal PTC for wind, and even up to a $40 per ton CO2 cost applied to every ton of emissions.

For both investor-owned and public power utilities:

§ A 500 MW SCPC unit is a lower cost baseload alternative than a 500 MW gas-fired CCGT without wind at CO2 costs exceeding $40 per ton.[19]

The base case assumptions used by Mr. Greig in his economic analysis are set forth in Table 1 of his prefiled testimony.[20] Mr. Greig testified that the capital cost assumptions he used for the generation alternatives were based on the midpoint of the range identified on page 20 of the Boston Pacific Report. Because Boston Pacific concluded that the fuel cost forecasts for natural gas and coal under the base case were reasonable, he retained those assumptions.[21] According to Mr. Greig, the capital cost, performance, and O & M cost estimates for the different generation alternatives were used as key inputs into a pro forma economic model that determined the annual cost of power for each alternative on a revenue requirements basis over a 20-year planning period. Two different economic models were prepared by Mr. Greig to reflect two different potential ownership structures, since two of the Applicants are investor-owned utilities and three are public power utilities. He assumed a 50% debt/50% equity financing structure for the investor-owned model and estimated an income tax liability component. For the public power model, tax-exempt debt financing through bonds was assumed for 100% of the estimated total project costs and no income tax liability was estimated. A 10.5% rate of return was used in the updated economic evaluation for the cost of equity, consistent with a rate adopted by the Commission in Otter Tail Power's recent rate case, but the other financing assumptions remained the same as were used in Mr. Greig's earlier evaluation in this case.[22]

[19] Applicants' Ex. 146 at 1-2, 16-17; T. Vol. 1 at 187-193.
[20] Applicants' Ex. 146 at 2.
[21] Applicants' Ex. 146 at 3.
[22] Applicants' Ex. 146 at 4.

With respect to investor-owned utilities, Mr. Greig's analysis compared a 500 MW SCPC alternative to a 500 MW CCGT alternative. Mr. Greig testified that the levelized costs were presented across the sensitivity range of CO2 costs of $0 per ton to $40 per ton, and that the CO2 cost range was modeled similar to an emissions tax and applied to every ton of CO2 emissions. The results of this modeling were presented in Figure 1 of Mr. Greig's prefiled testimony. He found that the 500 MW SCPC alternative represented a lower cost baseload generation alternative on a life-cycle basis considering capital and operating costs for an investor-owned utility. He testified that this conclusion was reaffirmed across the Commission-approved range of CO2 costs from $4-$30 per ton, and even at $40 per ton CO2 costs applied to every ton. Thus, he concluded that, "If utilities that need baseload capacity and energy are not allowed to add high efficient [sic] SCPC units, replacing that need with gas-fired CCGT capacity is likely to result in increased costs, even accounting for CO2 costs." He noted that the economic update assumed that higher CO2 costs are likely to cause an increase in the price of natural gas, as noted in prior testimony. Based on prior testimony provided in this case by Mr. Sansom (Mr. Hewson's colleague), Mr. Greig indicated that a $1.35/MMBtu cost increase at a $30 per ton CO2 cost was reflected in the economic evaluation across the range of CO2 cost sensitivities. Mr. Greig testified that it is reasonable to predict that significant CO2 costs would result in some fuel switching from higher carbon fuels such as coal and oil to natural gas, particularly for older, less efficient resources, and noted that fundamental economics supports the position that prices for a scarce commodity such as natural gas will increase if demand is increased.[23]

Figure 2 in Mr. Greig's prefiled testimony presented a comparison of levelized costs for investor-owned utilities comparing a 500 MW SCPC to a 425 MW CCGT plus Wind case with and without an assumed extension of the PTC. This alternative assumed construction of 500 MW of wind with a 15% capacity credit, with the wind operated at a 40% capacity factor. The analysis assumed, in accordance with the wind estimate developed by the Brattle Group, that the levelized cost of wind was $63.37/MWh (2015$) assuming the PTC was extended, and $81.04/MWh (2015$) assuming the PTC was no longer available in 2014/2015. Mr. Greig testified that, due to the ability to offset higher gas-fired energy costs with intermittent wind energy, there was a net decrease in the breakeven CO2 cost for the gas-fired CCGT case as compared to Figure 1. If Congress does, in fact, extend the federal PTC, Mr. Greig concluded that the breakeven CO2 cost is approximately $26 per ton; if the PTC is <u>not</u> extended, Mr. Greig determined that the breakeven CO2 cost between the two alternatives for an investor-owned utility is approximately $37 per ton (assuming in each instance that the cost is applied on every ton of CO2 emissions). If the PTC is not extended, Mr. Greig concluded that the 500 MW SCPC unit represents a lower cost baseload generation alternative on a life-cycle basis across the entire Commission-approved range of CO2 costs from $4-$30 per ton.[24]

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[23] Applicants' Ex. 146 at 4-7; T. Vol. 1 at 188-189. Mr. Sansom is ill and has taken a leave of absence from EVA. T. Vol. 2 at 52.
[24] Applicants' Ex. 146 at 7-9; T. Vol. 1 at 191.

Mr. Greig testified that the PTC will expire at the end of 2009 and its future is uncertain, particularly for 2014 or 2015. Congress could let the PTC expire, could enact a different structure or incentive, or could choose to substitute a national renewable standard. Due to this uncertainty, Burns and McDonnell provided analyses under both scenarios.[25]

Figure 3 in Mr. Greig's prefiled testimony presented a comparison of levelized costs for public power utilities comparing a 500 MW SCPC to a 425 MW CCGT plus Wind case with and without an assumed extension of the PTC, and across a sensitivity range of CO2 costs from $0-$40 per ton. The analysis assumed that the wind farm was owned and operated by an independent developer and purchased by the utility under a power purchase agreement, as well as an aggressive 40% net energy production factor. The resulting levelized cost of wind was $64.52 per MWh (2015$) assuming the PTC was extended, and $82.27 per MWh (2015$) assuming the PTC was no longer available in 2014/2015. Mr. Greig determined that the 500 MW SCPC unit represents a lower cost baseload generation alternative on a life-cycle basis considering capital and operating costs for a public power utility across the $4/ton to $30/ton range of CO2 costs, and even at $40/ton. Because the economics of the SCPC alternative were so favorable as compared to the CCGT plus Wind alternative for public power utilities, and because the CCGT plus Wind alternative was economically superior to a CCGT-only alternative for investor-owned utilities, Mr. Greig testified that he knew the SCPC alternative would be superior to a gas-fired CCGT-only alternative for public power utilities and concluded that he did not need to run a scenario comparing the SCPC and CCGT-only alternatives.[26]

Capital cost, fuel cost, and wind performance sensitivities were evaluated in Mr. Greig's updated economic analysis. In addition to the natural gas cost assumption suggested by Boston Pacific based on a symmetrical +/- 25% range, Mr. Greig prepared an alternative natural gas cost sensitivity based on a higher end risk scenario for natural gas cost increases. The base case and sensitivity assumptions used in the analysis are reflected in Table 2 of Mr. Greig's prefiled testimony.[27] The tornado diagram set forth in Figure 4 of Mr. Greig's prefiled testimony summarizes the results of the additional sensitivity analyses conducted for the investor-owned utilities.[28] The $26 per ton CO2 breakeven cost is set forth as the middle point of the diagram. According to Mr. Greig, as capital, fuel, PTC, and wind performance assumptions are modified, the breakeven CO2 cost changes. Mr. Greig found that the most important factors influencing the CO2 cost breakeven point are (a) natural gas costs, and (b) whether the PTC is extended. He determined that increasing natural gas costs increases the CO2 cost breakeven point between the SCPC and CCGT plus Wind alternatives. For example, he noted that an increase in the base case cost of natural gas of $1.00/MMBtu increases the CO2 cost breakeven point by almost $8 per ton, and a high gas case of $12.50/MMBtu increases the CO2 cost breakeven point to nearly $60 per ton. He testified that the

[25] Applicants' Ex. 146 at 9-10.
[26] Applicants' Ex. 146 at 10-12; T. Vol. 1 at 191.
[27] Applicants' Ex. 146 at 13; T. Vol. 1 at 191-194.
[28] Applicants' Ex. 146 at 14.

United States has experienced gas costs over $12/MMBtu during the last 12 months, in the absence of any federal CO2 regulatory regime. Because capital cost escalation would have an impact on each of the generation alternatives, and because the overall total investment required for 500 MW SCPC was not materially different from the investment required for a CCGT plus Wind alternative, Mr. Greig concluded that capital cost was a relatively low driver.[29]

Mr. Greig did not prepare a similar tornado diagram for the public power utilities. He determined that a tornado diagram illustration was not practical because there was no point even at $40 per ton of CO2 cost that the CCGT plus Wind alternative resulted in the same or lower levelized cost for a public power utility as a 500 MW SCPC unit. He testified that Burns & McDonnell is confident that the same drivers influence the public power results in a similar fashion.[30]

Mr. Greig testified that, while the economic analysis extended the CO2 cost sensitivities out to $40 per ton escalated, it did not extend the CO2 cost sensitivities to $60 per ton, as recommended by the Boston Pacific Report, for several reasons: (1) the Commission-approved range for CO2 costs is $4-$30 per ton and those are the most applicable values for evaluation in this proceeding; (2) the economic analysis provided the Commission with the breakeven or crossover point at which the SCPC and CCGT plus Wind alternatives have essentially equal levelized costs, and thereby gave the Commission the information needed to draw conclusions regarding even higher CO2 cost assumptions; (3) Burns & McDonnell did not believe that running a further sensitivity at $60 per ton would yield additional useful information.

Mr. Greig acknowledged that, at very high CO2 costs such as $60 per ton, a SCPC alternative is likely to be uneconomic against alternatives if all other assumptions are held equal. However, in his view, high CO2 costs will create feedback effects on other assumptions, particularly natural gas costs. He testified that $60 per ton CO2 costs could cause natural gas prices to increase to at least $14 per MMBtu and perhaps as high as $25 per MMBtu, which would dramatically affect the economic evaluation and make a SCPC alternative competitive against a CCGT plus Wind alternative.[31]

Mr. Greig testified that, in updating the analysis, he ran scenarios and obtained results for the endpoints of $0 and $40 per ton CO2 pricing, but did not run separate scenarios for numbers between the two endpoints. He testified that, because gas and coal plants each emit CO2 on a constant basis per MWh, the relationship is linear, and it was not necessary to run scenarios involving points between $0 and $40.[32] He used a natural gas price of $8.31 per MMBtu in the scenarios with a $0 per ton CO2 price, and a natural gas price of $10.06 in the scenarios with a $40 per ton CO2 price (an increase of 21.5 percent).[33]

[29] Applicants' Ex. 146 at 12-15; T. Vol. 1 at 191-194, 206.
[30] Applicants' Ex. 146 at 15; T. Vol. 1 at 213-214.
[31] Applicants' Ex. 146 at 15-16.
[32] T. Vol. 1 at 193-195.
[33] T. Vol. 1 at 197-198; see also T. Vol. 1 at 162-163 (Uggerud).

When Mr. Greig used the Boston Pacific gas prices in his analysis, he also adjusted the prices for the impact of CO2 regulation by incorporating the feedback effect that he believes would occur at high CO2 prices. He believes there would be a shift from coal-fired generation to natural gas-fired generation, which would increase the demand and the price for natural gas. He relied upon EVA testimony that showed that the feedback effect on natural gas prices at $30 per ton CO2 cost would be approximately $1.35 per million, or roughly 45 cents for every $10.[34] Mr. Greig testified that studies (including EIA studies) have concluded that the CO2 taxes will increase the demand for natural gas unless there is a significant amount of new nuclear energy added in the country or unless carbon capture and sequestration technologies are used on coal plants. Accordingly, he believes it is appropriate to include the feedback effect. He did not run the calculations without the feedback effect.[35]

According to Mr. Greig, the economics of a SCPC unit and the CCGT plus Wind combination are essentially equal if the price of gas is $6.23 and the CO2 tax is $9 per ton.[36] In terms of the breakeven point, Mr. Greig testified that it would take an $8 increase in the CO2 tax to offset each $1 increase in natural gas prices.[37] In his opinion, the CO2 price would have to reach $42 before the CCGT plus Wind alternative would become more competitive with the SCPC unit.[38]

Mr. Greig agrees that it is valuable to have a number of options run in order to increase the robust quality of decision-making. In his view, that quality is present here, since all five Applicants, using different models, have all independently come to the same conclusion, and Mr. Greig's analysis isolating baseload generation alternatives also demonstrates that Big Stone II is a lower-cost option across a set of alternatives.[39]

2. Marc Chupka

The Applicants retained Marc Chupka, a principal with The Brattle Group, to advise on the appropriateness of levelized cost analysis. The Brattle Group is primarily composed of economists. Over half of the work performed by The Brattle Group involves the energy industry. Mr. Chupka has had over 20 years of experience in both the public and private sector dealing with energy and environmental issues, and has had substantial involvement in climate change issues and utility resource planning. The Brattle Group was one of the two bidders for the work as the Commission's independent analyst in this proceeding.[40]

In his testimony, Mr. Chupka discussed the relative merits of levelized cost analysis and capacity expansion and optimization approaches, and how best to implement levelized cost analysis to illuminate the costs and risks associated with

[34] T. Vol. 1 at 199, 205-206, 211.
[35] T. Vol. 1 at 203.
[36] T. Vol. 1 at 208.
[37] T. Vol. 1 at 209-211.
[38] T. Vol. 1 at 212.
[39] T. Vol. 1 at 200-201.
[40] Applicants' Ex. 144 at 4; T. Vol. 2 at 94-96, 114-115.

selecting any particular baseload generating option. In his view, the Applicants have used an appropriate analytical framework to analyze the impact of alternative assumptions on the costs of alternative baseload options, and have used reasonable scenarios to explore the impact of various assumptions on the levelized costs of those options. He testified that construction costs have increased during the life of the Big Stone II project as a function of several simultaneous trends in global commodity, foreign exchange and service markets. He indicated that these trends have continued through 2008 although some commodity cost increases have abated somewhat. Mr. Chupka testified that rapidly changing costs of any type make resource planning much more difficult. He stated that uncertainty regarding construction costs exacerbates the inherent challenge of analyzing the economic trade-offs among resource options and requires utility resource planners to examine broad ranges of potential market outcomes and look at risks in a systematic manner.[41]

Mr. Chupka identified several principles to help guide resource selection in an era of highly uncertain construction costs. He testified that it is important to recognize that the current drivers of construction costs affect the cost of all projects in similar ways (but not necessarily with identical magnitude of impacts). In his opinion, when considering ranges of construction costs for economic modeling, it is logical to examine scenarios where construction costs are higher or lower than some reference level for *all* alternatives, rather than exploring sensitivity cases where the capital cost of one alternative is varied in isolation. Instead, in his view, the impact of all construction costs becoming higher or lower than expected should be explored, as reflected in Mr. Greig's prefiled rebuttal testimony. He testified that the economic evaluations provided by the Applicants incorporate both the upper and lower cost ranges identified by Boston Pacific for all technologies (i.e., the Applicants "are interpreting the higher and lower end of the ranges for <u>each</u> technology as indicative of scenarios in which capital costs are higher or lower than expected, *across the board*"). In his opinion, the approach taken by the Applicants is reasonable.[42]

Mr. Chupka testified that there is some evidence that the percentage increase in construction costs for natural gas and wind technologies has been higher than coal options. He noted that the IHS CERA Power Capital Costs Index, which tracks the cost of construction for coal, gas, wind and nuclear plants, has risen by 130% since 2000. During the same time frame, the cost of coal plants has risen by 78%, the cost of gas-fired plants has risen by 92%, and the cost of wind has increased by 108%. He also indicated that the Handy-Whitman Index of Public Utility Construction Costs shows that cost escalation for steam production plants (coal units) rose sharply between 2004 and 2008, while gas turbo-generators (combustion turbines) were relatively stable until 2006, after which they increased sharply. Between 2006 and 2008, the index for steam plants increased by 10.5%, while the index for gas turbo-generators increased by 33.6%.[43]

[41] Applicants' Ex. 147 at 1-3.
[42] Applicants' Ex. 147 at 3-4, 14.
[43] Applicants' Ex. 147 at 4-6 and Figure 1.

Mr. Chupka testified that utilities use many different approaches to resource planning issues. He indicated that production cost models are helpful for price forecasting and for developing fuel and power procurement strategies. He stated that they are often used for short-run assessments of utility system operation, since they optimize the utilization of various existing generating units, but do not necessarily assess long-run options for capacity expansion. Mr. Chupka stated that capacity expansion optimization models "are an appropriate tool to derive optimal resource expansion plans, given long-run forecasts of load growth, fuel prices, technology availability and future environmental requirements." Mr. Chupka indicated that capacity expansion models can help utilities determine a least-cost mix of various types of generating or demand-side resources and the best timing of such resource additions. They are able to assess a diverse range of supply and demand options, and perform economic comparisons of resources with very different characteristics. According to Mr. Chupka, levelized cost analysis "provides a useful and transparent approach for exploring a wide range of future costs, and for examining specific economic risks of selecting resource options in the face of the significant uncertainty in those costs, when certain conditions are met. These conditions include the presumption that the resource options are providing substantially equivalent services (e.g., firm baseload power) and where the need for and timing of such resources has already been established."[44] In his opinion, "once the type and timing of the resources are understood, levelized cost analysis is very appropriate and extremely useful for examining the risks inherent in any resource selection by looking at the effect on costs of varying input assumptions."[45]

Mr. Chupka testified that these conditions have been met in the current case. Based on the language of the Commissions' RFP, he concluded that the Commission is concerned about the costs and risks surrounding the selection of a resource option that will match the power and energy potential of a 500 MW supercritical pulverized coal plant such as Big Stone II. The Commission also identified a wind/gas alternative and a gas-only alternative providing identical annual generation commencing at a common in-service date. Mr. Chupka indicated that assumed capacity factors and in-service dates are fundamental input assumptions that enable proper levelized cost analyses. Under these conditions, he noted that levelized cost analysis can reveal break-even points that yield equal costs between two options, depict the magnitude of economic risks associated with selecting one technology over another across a broad range of future scenarios, and quantify the degree to which electricity costs differ between alternative resource options when future conditions depart from expected conditions.[46]

Mr. Chupka concluded that the levelized cost analysis provided by Mr. Greig was an appropriate method to address the issues raised by the Commission regarding resource costs and risks. He believes Mr. Greig used appropriate sets of assumptions and varied them in reasonable and sensible ways. Because the Commission is interested in the costs incurred from alternative baseload resources providing equivalent annual energy, he believes little insight would be gained from a capacity expansion

[44] Applicants' Ex. 147 at 6-7.
[45] T. Vol. 2 at 97.
[46] Applicants' Ex. 147 at 8-9; T. Vol. 2 at 97-98, 101-102.

model. He further indicated that it is not necessary to examine every combination of input assumptions to adequately analyze risks in a levelized cost analysis. He testified that one of the virtues of levelized cost analysis is the transparency of the results. Because not every combination of future input assumptions is equally plausible, he finds it “useful to define discrete scenarios that reflect a particular view of how the world might evolve, when exploring sensitivities with more than one input variable.” He testified that a valid scenario is one in which the changes in the values of variables are performed in a coherent manner. For example, he indicated that, “in exploring different assumptions regarding construction costs, it is not sensible to assume that one alternative’s construction costs will rise while another will fall, since the same drivers are likely to affect all construction costs.” Mr. Chupka maintained that the same principle applies to other inputs, although he noted that the degree to which input variables are likely to be correlated varies.[47]

Mr. Chupka asserted that natural gas prices and CO2 allowance prices “may well be correlated” under cap-and-trade systems and as discussed in Mr. Hewson’s testimony. Under these conditions, Mr. Chupka indicated that "levelized cost analysis can focus on scenarios where high natural gas prices and high CO2 allowance prices are assumed together, and place less emphasis on scenarios that combine high natural gas prices with low CO2 prices, and vice versa."[48] He expects that CO2 regulation will increase natural gas prices on a net basis, particularly as higher CO2 values are reached.[49] Mr. Chupka noted that it is necessary to look at total natural gas demand, not just demand in the power sector, because a number of other sectors use natural gas and, if natural gas prices rise, there are other industries and users who might reduce their natural gas use and take some of the pressure off natural gas demand.[50] However, he believes that other industries that are heavily reliant on natural gas have already either switched or shut down due to the high natural gas prices that have been occurring, so the offsetting influence is likely weaker than the direct impact from increased demand for power generation.[51]

Mr. Chupka also provided estimates of the levelized busbar costs of wind under alternative ownership, tax credit and capacity factor assumptions, using the capital costs provided by Boston Pacific. He considered two ownership models (an investor-owned utility, and an independent developer selling wind power under a 20-year power purchase agreement). He considered one scenario in which the PTC is available and one in which it is not available. He also considered three construction cost scenarios (the high, low and mid-point suggested by Boston Pacific) and two capacity factors (35% and 40%). Overall, Mr. Chupka produced 24 separate estimates of levelized wind costs. The results are summarized in Figure 2 of his pre-filed testimony. Levelized costs ranged from $60.11 (assuming utility ownership, low construction costs and Ariel with PTC and a 40% capacity factor) to $97.81 (assuming the power purchase agreement, high construction cost scenario without PTC and a 35% capacity factor).

[47] Applicants’ Ex. 147 at 9-10.
[48] Applicants' Ex. 147 at 10-11; T. Vol. 2 at 98-101, 116.
[49] T. Vol. 2 at 120-121.
[50] T. Vol. 2 at 115-116, 120-121.
[51] T. Vol. 2 at 121.

Mr. Chupka concluded that estimates of wind power costs are very sensitive to the status of the PTC. Depending on other conditions assumed, levelized costs are between 22 and 29% higher when the PTC is not available. He also concluded that estimates of wind power costs are moderately sensitive to capacity factor assumptions. He found that a wind plant with a 35% capacity factor is between 14% (without PTC) and 18% (with PTC) more expensive. The range of capital costs and ownership assumptions examined did not strongly affect the levelized cost of wind power.[52]

In an article in the *Engineering News Record* dated June 23, 2008, Mr. Chupka is reported as stating during an interview that a combination of soaring capital costs and uncertainty about future carbon rules have slowed the pace of coal plant development and that, for the time being, combined cycle and peaking plants fueled by gas "seem to be the fossil-fuel options that make the most sense, given the capital costs and the political situation."[53] Mr. Chupka testified that he was making observations regarding very broad industry trends at that time. He indicated that, as coal plant development has slowed down, there appears to be a trend toward utilities planning to build new natural gas generation.[54]

During cross examination, Mr. Chupka acknowledged that current utility sales and demands might be reduced as a result of an economic slowdown but may increase once economic recovery is maintained.[55]

In a newsletter issued by The Brattle Group that was co-authored by Mr. Chupka, utilities were advised of the need to enhance "traditional" IRP in light of uncertainties and tradeoffs regarding difficult issues such as climate change, national security, and the impact of high fuel costs. The newsletter stated:

> Traditional IRP does not address whether it is advantageous to make a bet on a promising technology that nonetheless has significant disadvantages in some possible futures. It does not commit only to a plan that performs reasonably well under any potential future state of the world, nor does it pursue short-term strategies such as market purchases that may buy time in the hope that some uncertainties will be resolved. It also does not address the diminished degree of control that utilities and state regulators have over regional market outcomes, particularly in restructured states. A broader approach must be taken in order to address the enormous uncertainty and tradeoffs among competing policy objectives. Rather than optimizing resources against an assumed future, explicit consideration of the wide range of uncertainty can add valuable insight.[56]

In response to Judge Mihalchick's questions at the hearing, Mr. Chupka testified that, in his own practice, he "tends to look at several modeling approaches, including levelized

[52] Applicants' Ex. 147 at 11-13 and Figure 2; T. Vol. 2 at 98-99.
[53] Joint Intervenors' Ex. 56 at 2; T. Vol. 2 at 109-110.
[54] T. Vol. 2 at 119-120.
[55] T. Vol. 2 at 110-111.
[56] Joint Intervenors' Ex. 57 at 2.

cost analysis, to get behind some of the numbers and to explore how variations in these highly uncertain factors [such as CO2 and natural gas prices] really impact costs and potentially resource selections themselves." He indicated that IRPs have evolved over the past five to ten years to incorporate much more attention to these factors. Historically people have used . . . very narrow sensitivity bands, for example, and they discovered over time that . . . they should not have that kind of confidence in their . . . base case assumptions that they previously did."[57]

3. Ward Uggerud

Ward Uggerud, Senior Vice President of Otter Tail Power Company, testified that levelized cost analysis provides an analytic framework directly responsive to the Commission's inquiries in the current phase of these proceedings. He also emphasized that each of the project participants performed capacity expansion modeling as a fundamental input into their resource selection decisions. Mr. Uggerud indicated that the key variables in the analysis are the levels of assumed natural gas prices and future CO2 regulatory costs. According to Mr. Uggerud, the Burns & McDonnell analysis confirms that Big Stone II is the more economic resource choice even under aggressive CO2 regulatory assumptions. Although he noted that the project "can be made to seem uneconomic as against a hypothetical but unrealistic wind-gas alternative for investor-utilities if one assumes very high carbon dioxide prices without a feedback effect on natural gas prices," the Applicants' experts believe that very high CO2 values are unlikely and that, if they occur, they will be accompanied by very high natural gas prices.[58]

B. Boston Pacific Report and Testimony

Craig Roach and Frank Mossburg wrote the Boston Pacific Report and testified on behalf of Boston Pacific. The Boston Pacific Report expressed the view that Applicants should engage in the more sophisticated analysis afforded by capacity expansion models, and such tools should be used to test the impact on resource selection of the full range of inputs.[59]

Dr. Roach testified that Boston Pacific continues to have issues with several aspects of Mr. Greig's analysis. First, he noted that Mr. Greig characterizes the natural gas/wind technology as two separate power plants (one a wind farm and one a natural gas power plant) and that, under such an analysis, both would incur substantial transmission costs. Dr. Roach would like to see additional alternatives considered, such as a combination of less expensive combustion turbines and wind, and whether or not those could be located in a manner that would minimize transmission costs.[60] In addition, to ensure that the Commission is given the necessary information to make a decision in this case, Boston Pacific would have preferred that Mr. Greig look at a broader range of policies that might give an advantage to wind other than simply the

[57] T. Vol. 2 at 124-125.
[58] Applicants' Ex. 144 at 12; T. Vol. 1 at 147-149.
[59] ALJ Ex. 2 at 5-6, 15, 20; T. Vol. 1 at 22, 104-106.
[60] T. Vol. I at 12-14.

production tax credit. Although Dr. Roach agrees that Congress extending the production tax credit is very important to the cost of the wind and natural gas options, he asserted that other policies also would give a boost to wind, such as a renewable portfolio standard and sale of renewable energy credits.[61]

According to Dr. Roach, more powerful analytic tools are needed than levelization in a situation like this, where very different technologies are being compared. He acknowledged that levelization analysis can be a useful tool and indicated that Boston Pacific often uses such an approach is as an initial screen. However, in his opinion, the more complex method of analysis offered by capacity expansion models helps in making decisions where distinctly different technologies are being compared.[62] He noted that, in Mr. Greig's analysis, a coal plant was compared to a wind/gas plant that runs all the time. However, a capacity expansion model could take broader options into account, such as natural gas, wind, and market purchases. In addition, different configurations could be tested, such as combustion turbines plus wind plus market purchases, and it would be possible to test whether a joint gas plant would work for the Applicants.[63] Mr. Mossburg testified that, even when somewhat similar technologies are involved, use of a capacity expansion model enables one to test the feasibility of various arrangements to a greater extent than use of levelization.[64]

Boston Pacific noted that, to address uncertainty and do a complete job in testing the range of assumptions, the Applicants may have to go to a capacity expansion model.[65] In particular, Dr. Roach noted that the Strategist model would help ask all of the right questions, especially questions about some of the alternatives.[66] One possibility, according to Dr. Roach, would be to conduct one unified Strategist run for all five Applicants.[67] In the alternative, risk could be assigned to various parties rather than to consumers.[68]

Dr. Roach testified that Mr. Greig in his rebuttal testimony began to add some things and address some questions that he thought were useful. However, Dr. Roach noted that he continued to have questions, and felt that the type of robust analysis he was seeking continued to be lacking.[69] Dr. Roach thinks there are other factors beyond the tornado charts in Mr. Greig's testimony that should be considered by the Commission with respect to this decision. For example, he believes the Commission would want to see an analysis without the inevitable CO_2/natural gas price link (discussed further below). In addition, he testified that, when analyzing natural gas/wind options, Mr. Greig doubled up transmission costs by putting approximately $400 per kW on twice. He believes the Commission might want to see an analysis where that does

[61] T. Vol. I at 15-16, 67.
[62] T. Vol. 1 at 15, 69, 113-114.
[63] T. Vol. 1 at 69-70, 73.
[64] T. Vol. 1 at 114-115.
[65] T. Vol. 1 at 71.
[66] T. Vol. 1 at 106.
[67] T. Vol. 1 at 117-120.
[68] T. Vol. 1 at 110-113, 122-124.
[69] T. Vol. 2 at 131.

not occur and where there is a better optimized addition of resources. He also reiterated that perhaps there should be consideration of whether it would be better to have a combustion turbine than a combined cycle and whether another renewable policy (such as renewable portfolio standards and the use of renewable energy credits) might give a boost to wind if the PTC was no longer in effect.[70]

C. Testimony on Behalf of Joint Intervenors

David Schlissel, Senior Consultant at Synapse Energy Economics, Inc., agreed with Boston Pacific's conclusion that, given the uncertainties surrounding the nature and cost of greenhouse gas regulations, construction costs, and future natural gas and coal prices, all resource options must be assessed under a range of futures to assure ratepayers will get the best deal possible no matter how the future unfolds. In his opinion, the Applicants have not considered reasonable ranges of future CO2 prices and power plant construction costs in their analysis. He asserted that MDU did not assume any CO2 emissions price, and the remainder of the Applicants considered at most a $9 per ton CO2 emissions price in their modeling analyses.[71]

With respect to Mr. Greig's levelized busbar analyses, Mr. Schlissel supported the use of a $30/ton CO2 price as being within a reasonable range, but asserted that Mr. Greig's analysis was heavily biased in favor of Big Stone II by virtue of his assumption that the $30/ton CO2 price would not increase over time and his assumption that a $30/ton CO2 price would increase natural gas prices by 17%.[72]

II. Carbon Regulation Costs

A. Boston Pacific Report and Testimony

In its Report, Boston Pacific indicated that the Applicants attempted to examine the effect of future CO2 costs in two ways. First, in their capacity expansion modeling, the Applicants looked at resource selection using a range of costs from $0-$9 per ton of CO2. Because the $9 per ton cost was not escalated, Boston Pacific stated that the cost decreased in real (inflation-adjusted) terms over time. Second, as noted above, Mr. Greig presented a busbar analysis comparing Big Stone II's likely annual cost (i.e., fuel costs, fixed and variable operating and maintenance charges, capital charges and emissions costs) to those of a new gas-fired combined cycle unit and wind market purchases with a combined cycle back-up. While Mr. Greig examined CO2 cost levels ranging from $4 - $30 per ton, Boston Pacific indicated that these amounts were not escalated over time.[73]

Boston Pacific found "the Applicants' use of a $0 to $9 per ton CO2 tax, without escalation over time, to be far lower than the ranges justified for resource decisions today" and determined that the Applicants' "later use of a $30 per ton tax was a good

[70] T. Vol. 2 at 131-132.
[71] Joint Intervenors' Ex. 50 at 1-2.
[72] Joint Intervenors' Ex. 50 at 14.
[73] ALJ Ex. 2 at 8.

step forward but did not go far enough."[74] In its report, Boston Pacific recommended that resource choices be analyzed under four different levels of CO_2 taxes: $8, $20, $40 and $60 per ton of CO_2, starting in 2012, and escalating with inflation thereafter.[75] According to Boston Pacific, "[t]he goal of these analyses will be to identify, if possible, a portfolio of resources that deliver low cost supply to ratepayers under a variety of greenhouse gas regimes" and "reveal the breakpoints; that is, what level of CO_2 tax switch[es] the choice from one resource to another."[76] Boston Pacific stated that this recommendation is supported by recent CO_2 allowance prices as traded in the open market worldwide; studies estimating the cost impact of various pieces of climate change legislation; estimates of the CO_2 tax levels needed to actually reduce emission levels; and the ranges of estimates used in a sample of actual Integrated Resource Plans.[77]

In testimony at the evidentiary hearing, Dr. Roach noted that the Applicants' rebuttal showed better practices in the manner in which they tested their analysis over the ranges suggested by Boston Pacific. In particular, he found Mr. Greig's testimony relating to the CO_2 breakpoint to be constructive. According to Mr. Greig, under the Applicants' base case assumptions (and assuming the production tax credit was extended), the resource decision would favor coal-fired power for investor-owned utilities if the CO_2 tax is $26 per ton or lower, and the resource decision would favor some combination of natural gas and wind if the tax is higher than $26 per ton. Dr. Roach also found it constructive that Mr. Greig determined that natural gas prices drive that breakpoint up or down. For example, over the range of natural gas prices suggested in the Boston Pacific report, low gas prices would push the breakpoint down to $9 and high gas prices would increase the breakpoint to $42.[78]

Mr. Mossburg testified that, while Mr. Greig used the $30 per ton of CO_2 figure in his testimony, the highest number used in the Applicants' capacity expansion models was $9 per ton.[79] Mr. Mossburg indicated that, at the $30 per ton price, Mr. Greig increased the base cost of natural gas by $1.35 per MMBtu to reflect climate change legislation. He testified that the $26 per ton breakpoint would have been lower if Mr. Greig had not increased the natural gas prices so much.[80]

In Dr. Roach's view, the $4 to $30 range previously adopted by the Commission with respect to future CO_2 risks does not represent best industry practice.[81] Dr. Roach acknowledged that it is difficult to predict the consequences of any particular piece of

[74] ALJ Ex. 2 at 5 (citation omitted).
[75] ALJ Ex. 2 at 5.
[76] ALJ Ex. 2 at 15-16.
[77] ALJ Ex. 2 at 5, 7-15.
[78] T. Vol. I at 12-14, 17-18.
[79] T. Vol. 1 at 37.
[80] T. Vol. 1 at 89.
[81] T. Vol. 1 at 40.

carbon emissions legislation. In his opinion, the more probable numbers are in the $25 to $40 range.[82]

B. Testimony of Applicants' Witnesses

1. Ward Uggerud

Mr. Uggerud outlined several areas of disagreement with Boston Pacific's discussion of potential carbon dioxide regulatory costs. He emphasized that the Boston Pacific report did not state whether any one of the four CO2 values was more probable. He testified that the Applicants disagree with any implication that each of these values is equally likely and should be given equal weight. He indicated that the Applicants believe that the higher end numbers are less likely than the lower end numbers, and their decision to select Big Stone II over viable alternatives reflects this judgment. Mr. Uggerud noted that the $40 and $60 values exceed the $4 - $30 range recently established by the Commission after review of much of the same information, as well as the value that the Joint Intervenors found most likely. In his view, a CO2 tax that exceeds $40 a ton on every ton of carbon produced from a coal-fired power plant is unlikely because of the economic impact that would be involved.[83] In addition, Mr. Uggerud noted that a CO2 tax approaching $60 per ton would levy huge costs on society and is unlikely, particularly in light of current economic conditions.[84]

Mr. Uggerud also testified that Boston Pacific's discussion of potential CO2 regulatory costs lacked context and does not account for the derivation of the CO2 numbers that Applicants modeled. In particular, he asserted that the Applicants have used the current CO2 planning costs established by the Commission throughout this proceeding, or the Applicants' best estimate of the costs that the Commission would adopt next. He indicated that, in their initial filing, the Applicants used zero cost because that was the cost for out-of-state plants at that time, and they used $3.65/ton as a sensitivity case because that was the highest value then being used by the Commission for in-state plants. He further stated that the Applicants used $9/ton in November 2007 because that was the cost the Department of Commerce was proposing as an interim value, and they used the $4 to $30/ton cost range adopted by the Commission in December 2007 in connection with Mr. Greig's testimony filed in January 2008.[85]

Mr. Uggerud asserted that the Applicants did not in fact limit their analysis to an upper range value of $30 per ton of CO2 based upon a contention that Mr. Greig's calculation of a CO2 "cross-over" point implicitly examined a broader range of values. He testified that most of the runs showed a cross-over point of greater than $30.[86] Finally, Mr. Uggerud indicated that Mr. Greig's recent analysis considering an $8-$60

[82] T. Vol. 1 at 107-108.
[83] T. Vol. 1 at 140-141.
[84] Applicants' Ex. 144 at 9, 10.
[85] Applicants' Ex. 144 at 9, 11.
[86] Applicants' Ex. 144 at 9-10; T. Vol. 1 at 142 (under the likely scenario of associated costs of the alternatives, Applicants see a break-even point of $37 - $40 or more per ton).

range under various assumptions continues to justify the Applicants' investment in Big Stone II.[87]

Mr. Uggerud testified that the Applicants disagree with Boston Pacific's suggestion that carbon dioxide costs are likely to achieve levels up to $60 per ton in the near and mid-term, applied to all tons of emissions. If CO2 costs do reach the $60/ton level, Mr. Uggerud testified that there would be a very dramatic increase in natural gas prices that would result in Big Stone II maintaining its superiority over a gas-fired alternative.[88] Relying upon Mr. Greig's levelized cost model using the range of CO2 values recommended by Boston Pacific, along with a range of other assumptions, Mr. Uggerud testified that, under the most reasonable set of assumptions, Big Stone II continues to represent the appropriate and prudent resource choice.[89]

2. Thomas Hewson

Thomas Hewson, a Principal with Energy Ventures Analysis, Inc., a consulting firm that makes energy projections, submitted testimony relating to the carbon emission costs.[90] Mr. Hewson testified that the cost to Big Stone II of carbon dioxide regulation is likely to be in the lower half of the Boston Pacific $8-$60/ton CO2 range. He provided several reasons for this projection:

(1) he asserted that, for the most part, the high-end estimates of allowance prices under the Lieberman-Warner bill and other proposals occur in the "out" years (when emission reduction requirements become more stringent), and some of the bills only showed out-year costs of $25-32 dollars with even lower near-term costs;

(2) he indicated that the fact that allowances were recently auctioned at $3.07 per ton under the Northeast regional cap and trade program and allowances are available on the Chicago Climate Exchange for about $2 per ton does not support the conclusion that prices will reach $40-$60; and

(3) he testified that the estimates of future CO2 costs contained in the IRPs of the six utilities discussed in the Boston Pacific report support the view that allowance prices as high as $60 are unlikely, since none of them showed $60 prices, only two showed prices exceeding $40, three did not show prices above $25, and one did not show a price above $10.[91]

Mr. Hewson also testified regarding several other reasons he considers values in the higher-end range to be less likely than values in the lower-end range. For example, he stated in his prefiled testimony that the Joint Intervenors presented low, mid, and high case levelized carbon dioxide values of $7.8, $19.1, and $30.5, and indicated that

[87] Applicants' Ex. 144 at 10.
[88] Applicants' Ex. 144 at 5.
[89] Applicants' Ex. 144 at 4, 5.
[90] Applicants' Ex. 148; T. Vol. 2 at 51.
[91] Applicants' Ex. 148 at 1-2, 3; T. Vol. 2 at 54-55.

the middle value was the most likely.[92] Mr. Hewson became aware after he filed his testimony that Joint Intervenors' additional rebuttal testimony offered in this proceeding set forth a new range of 2008 CO2 price forecasts which included low, mid and high case levelized CO2 values of $15, $30, and $45 per ton.[93]

Mr. Hewson also testified that Boston Pacific did not take into consideration the possibility that some allowances will be allocated to generators at no charge. However, he acknowledged at the hearing that Boston Pacific did discuss the opportunity costs of free allowances in its report. Mr. Hewson asserted that the Lieberman-Warner bill examined by Boston Pacific would have allocated a substantial number of no-cost allowances to the Big Stone II project which would roughly have cut in half the project's costs of complying with its provisions during the first half of its book life. Mr. Hewson testified that many of the bills considered by Congress have cost-containment or allowance ceiling prices to lessen economic impact, and he believes that mitigating the cost impact of climate change legislation is likely to become a key consideration as Congress focuses on economic recovery. In addition, he indicated that many of the bills allow generators to purchase low-cost offsets in lieu of purchasing allowances, and predicted that offsets will tend to lower allowance prices by reducing the demand for allowances.[94]

Mr. Hewson asserted that technological development will dampen allowance prices and that, once commercialized, carbon capture and sequestration technology will allow the capture of CO2 from coal generators at costs considerably less than the high-end numbers in the Boston Pacific report. In this regard, he noted that EPRI estimated in its 2006 and 2008 reports that the cost of carbon capture technologies may decrease to $20-23 per ton CO2 in the intermediate term. He further indicated that Alstom (a major equipment vendor) projects that its chilled ammonia process could reduce CO2 costs to less than $20 per ton, and DOE issued a carbon sequestration plan in 2006 in which it set its target goal as less than $10 per ton of CO2. At the hearing, Mr. Hewson acknowledged that there are other estimates of the cost of carbon capture and sequestration in the context of current sets of technologies that have much higher ranges. He also noted that there is concern about the costs and legal implications of injecting CO2 deep into the ground.[95]

Mr. Hewson testified that a new supercritical coal unit such as Big Stone II should have significant cost advantages over most existing coal units because its carbon capture and sequestration costs would likely be below average industry cost. He noted that the advantages of Big Stone II include economies of scale; an open site providing easy access and low retrofit costs for future carbon capture technologies (once cost-competitive); energy efficiency advantages as a supercritical coal unit; a location close to potential future carbon sequestration sites in South Dakota (leading to lower transport

[92] Applicants' Ex. 148 at 4; T. Vol. 2 at 67.
[93] T. Vol. 2 at 67.
[94] Applicants' Ex. 148 at 4-5; T. Vol. 2 at 67-68, 90-91.
[95] T. Vol. 2 at 70-71, 87-89.

costs); and lower delivered fuel costs because of its location near low-cost Powder River Basin coal.[96]

During the hearing, Mr. Hewson was asked about testimony concerning carbon risk and future CO2 costs in a hearing before the Colorado Public Utilities Commission during the summer of 2008 in which he participated. The proceeding involved the resource plan for Xcel Energy's affiliate Public Service of Colorado. In those proceedings, Public Service of Colorado initially used a base cost for CO2 of $20 per ton starting in 2010 and escalating at the rate of inflation and presented sensitivity analyses assuming CO2 prices of $10-$40 per ton in 2010. Later, during rebuttal, it increased the rate at which it escalated its base cost and sensitivity cost for CO2 from the rate of inflation to 7% per year. Ultimately, Public Service of Colorado recommended to the Colorado Commission a base case levelized CO2 cost of $35.52 per short ton.[97] The utility noted in its rebuttal testimony:

> Note that the high sensitivity case above is generally above the surveyed results, especially in the years after 2017. We believe, however, that this case represents a reasonable upper bound for the cost of a potential carbon policy, especially in light of the significant uncertainty associated with estimating future carbon costs. Small changes in economic factors or policy design--e.g. higher gas prices, lower national nuclear penetration, or reduced access to domestic offsets and/or international allowances--could cause carbon prices under a reasonably stringent carbon cap to rise into this range. In fact, this range is consistent with carbon prices estimated under high cost/low offset cases run by EIA and EPA.[98]

According to Mr. Hewson, there is a significant likelihood that the United States will adopt climate change regulation in the cap-and-trade format, but the timing, the costs, and allocations remain uncertain. He also believes that it is likely that President-Elect Obama will propose legislation for climate change.[99]

Mr. Hewson testified that his firm projects that 54 percent of conventional gas sources arguably will be depleted by 2030. He believes that approximately 30 percent of the needed additional gas expansion will come from shale and subsoil clays; 39 percent will come from imported liquified natural gas (LNG); 15 percent will come from new Canadian gas; and 16 percent will come from Arctic gas. He indicated that development of shale gas raises environmental concerns involving underground water contamination, and noted that development of an LNG facility requires a very large capital investment and a lengthy time period to obtain a permit. Mr. Hewson is concerned that the price of LNG could rise to the level of oil-based prices of $15-$25/MMBtu. He acknowledged that some new LNG terminals have come on line, are

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[96] Applicants' Ex. 148 at 4-6; T. Vol. 2 at 78.
[97] T. Vol. 2 at 59, 64-65; Joint Intervenors' Ex. 53 (Rebuttal Testimony of Frank P. Prager dated June 9, 2008) at 10.
[98] Joint Intervenors' Ex. 53 at 11; T. Vol. 2 at 63-64.
[99] T. Vol. 2 at 68-69.

being permitted, or are in the process of being constructed in the United States, Mexico, and northeastern Canada.[100]

3. Marc Chupka

Mr. Chupka testified that he found the Boston Pacific range of $8, $20, $40 and $60 very broad and would have preferred to see some different weights or different probabilities attached to those outcomes. He believes there is a stronger probability of an outcome between $20 and $40 than there would be outside of that range.[101]

B. Testimony on Behalf of Joint Intervenors

Mr. Schlissel provided testimony on behalf of the Joint Intervenors in response to the Boston Pacific Report. Mr. Schlissel agreed with Boston Pacific's conclusion that resource choices must be assessed over a range of possible future CO2 prices. Although he generally agreed with the range of CO2 emission prices recommended by Boston Pacific, he believes the low end of that range ($8/ton in 2012 escalating at the rate of inflation) is too low and would not reduce greenhouse gas emissions to the extent necessary to avoid the most harmful impacts of climate change.[102]

Mr. Schlissel testified that, in July 2008, Synapse revised the range of CO2 emission prices that it recommended be used in resource planning. The revision was made by Synapse in order to ensure that its forecasts reflected an appropriate level of financial risk associated with greenhouse gas emissions. Synapse was prompted to make the revision due to its determination that political support for serious climate change legislation has expanded significantly, the new greenhouse gas regulation bills under consideration in Congress contain stricter emissions reductions than previous proposals, an increasing number of states have adopted policies to reduce greenhouse gas emissions, and additional information is available regarding innovations in technology and the cost of emissions mitigation.[103]

Synapse's new low CO2 price forecast starts at $10/ton in 2013 and increases to approximately $23/ton in 2030, representing a $15/ton levelized price over the period 2013-2030 (all in 2007$). Synapse's new high CO2 price forecast starts at $30/ton in 2013 and rises to approximately $68/ton in 2030, representing a $45/ton levelized price over the period 2013-2030 (all in 2007$). Its new mid CO2 price forecast starts at $15/ton in 2013 and rises to $53/ton by 2030, representing a $30/ton levelized cost (all in 2007$). Mr. Schlissel testified that, in levelized terms, the Boston Pacific and Synapse ranges of CO2 emissions prices are reasonably consistent. Boston Pacific's range of recommended CO2 emissions prices in levelized terms is between a low end

[100] T. Vol. 2 at 79-80, 83, 84, 86, 91: Applicants' Ex. 148 at 8-9.
[101] T. Vol. 2 at 117-118.
[102] Joint Intervenors' Ex. 50 at 5.
[103] Joint Intervenors' Ex. 50 at 5-6.

of \$7.07/ton to a high end of \$53.03/ton, while Synapse's recommended CO2 emissions prices are between \$15/ton and \$45/ton (all in 2007\$).[104]

Mr. Schlissel testified that Synapse had reviewed the results of fourteen other modeling analyses that have been undertaken to evaluate the CO2 emissions allowance prices that likely would result from implementation of the major greenhouse gas regulatory legislation that has been introduced in the current Congress. These analyses were performed by the Energy Information Administration of the U.S. Department of Energy, the U.S. Environmental Protection Agency, the Massachusetts Institute of Technology, Duke University and RTI international, the Natural Resources Defense Council, the Clean Air Task Force, CRA International, and the American Council for Capital Formation and the National Association of Manufacturers. According to Mr. Schlissel, these modeling analyses examined more than 75 different scenarios reflecting a wide range of assumptions. The results of these modeling analyses are presented in Figures 1 and 2 of Mr. Schlissel's prefiled testimony, along with the CO2 prices recommended by Synapse and Boston Pacific.[105] During the hearing, Mr. Schlissel provided a revised version of Figure 2 that included the results of three more analyses (an Xcel Energy Company analysis of CO2 costs from a 2008 Colorado proceeding, a range of CO2 costs from an IRP study conducted by The Brattle Group in January 2008, and a range of CO2 costs that were used by in Black and Veatch in an October 2007 report).[106]

Based upon this review, Mr. Schlissel concluded that the ranges of CO2 prices recommended by Synapse and Boston Pacific are very reasonable compared to the full range of CO2 emissions allowance prices that could result from adoption of the major greenhouse gas regulatory legislation that has been introduced in the current U.S. Congress. He noted that there are a number of possible scenarios where CO2 emissions allowance prices could be substantially higher than the high ends of the price ranges that Synapse and Boston Pacific have recommended.[107] He also testified that it appears that the new President and Congress will seek to take aggressive and expeditious action to address the threat of climate change.[108] Mr. Schlissel further asserted that utilities conducting resource planning should not assume that there will be a free allocation of allowances, but should assume that they will have to pay for every allowance.[109]

Mr. Schlissel testified that allowance prices under a federal cap-and-trade program will be affected by many factors, such as geographic scope, sector coverage, stringency, use of flexibility mechanisms, portfolio of policy tools, and technological innovation. In Mr. Schlissel's view, the results of the recent Regional Greenhouse Gas Initiative (RGGI) auction of emissions allowances are not instructive regarding what emissions prices would be under a federal cap-and-trade program because the RGGI

[104] Joint Intervenors' Ex. 50 at 5.
[105] Joint Intervenors' Ex. 50 at 6-10.
[106] T. Vol. 2 at 148-149, 158-159; Joint Intervenors' Ex. 59.
[107] Joint Intervenors' Ex. 50 at 6-10; T. Vol. 2 at 157-158.
[108] Joint Intervenors' Ex. 50 at 11-12.
[109] T. Vol. 2 at 158-159.

program differs from a likely federal program in many ways. For example, he indicated that most proposals for a federal program have been expansive, covering the entire nation and multiple sectors, and have included more stringent long-term emission reduction targets than those contained in RGGI. In contrast, he indicated that the RGGI program is limited in geography and coverage; the RGGI cap applies only to the electric sector; RGGI states are geographically adjacent to regions that are currently do not have carbon constraints; generators can sell electricity into RGGI, diluting the effectiveness of the emissions cap; and RGGI has less stringent long-term emission reduction targets. He testified that the limited geography and coverage of the RGGI would lower the cost of emissions allowances below what they would be in a more comprehensive program, and that allowance prices under a more aggressive emission reduction target will be higher than those under a less aggressive emission reduction target, all other things being equal.[110]

Mr. Schlissel asserted that Mr. Hewson presented an overly optimistic view of carbon capture and sequestration costs and failed to acknowledge that other impartial, informed sources in government, academia, and the electric utility industry have projected much higher costs for carbon capture and sequestration. According to Mr. Schlissel, reports by Duke Energy Indiana, MIT, Edison Electric Institute, and the National Energy Technology Laboratory Project have estimated increases in the cost of electricity from addition of carbon capture ranging from 61% to 81%. Mr. Schlissel indicated that no power plants operating today capture and sequester CO2, and many questions remain in terms of the technical feasibility and economics of carbon capture and sequestration. As a result, he believes it is risky for a company or a commission to rely on the availability of such technology.[111]

Although the above cost projections were issued approximately one year ago based upon technologies that were under study at that time, Mr. Schlissel testified that the technologies have not changed much since that time. He indicated that perhaps costs would go down as technologies are better understood, but perhaps the actual costs will be much higher than originally estimated. In addition to the costs of carbon capture, Mr. Schlissel testified that an additional cost of approximately $5-$10 per ton is probably reasonable to encompass transportation and sequestration costs. Transportation would be the easiest and lowest-cost portion, but Mr. Schlissel believes that there would not be much economy of scale associated with transportation because additional pipelines will be needed to link to more plants. He indicated that there are uncertainties and problems associated with the carbon capture technologies that are currently being tested, including the chilled ammonia technology mentioned by Mr. Hewson.[112]

[110] Joint Intervenors' Ex. 50 at 12-13; T. Vol. 2 at 205-209.
[111] T. Vol. 2 at 159, 217-218, 230; Joint Intervenors' Ex. 60.
[112] T. Vol. 2 at 229-232.

III. Construction Costs

A. Boston Pacific Report and Testimony

Boston Pacific noted in its report that "construction costs for new generation are rapidly escalating due to run ups in commodity prices (e.g. steel) and increased demand for specialized labor and equipment. According to the IHS CERA Power Capital Costs Index (PCCI), which measures the construction costs of new facilities, costs for building new power plants have more than doubled since 2000 and have risen 69 percent since 2005 alone."[113] This portion of the report refers to all generation, not just coal generation.[114] Since 2000, wind has shown the largest increase (108 percent), followed by gas (92 percent increase) and coal (78 percent increase).[115] Dr. Roach noted that a wind provider might be willing to fix its capital cost on the day of the bid, as opposed to some conventional technologies.[116] Dr. Roach also testified that the theme of some recent studies is that the capital cost of renewables will decline as manufacturing scale increases.[117]

Boston Pacific estimated the installed costs for new coal-fired facilities to be from $2,600 per kW to $3,000 per kW. These costs reflect installed costs in nominal dollars for a new brownfield plant without interest during construction (IDC) or transmission integration costs. According to the Boston Pacific report, the Applicants' latest analysis used an estimate of $2,545 per kW for the installed costs for Big Stone II. Boston Pacific noted that this number was below even the low end of its estimate of the possible range of installed costs for a new coal-fired facility.[118]

According to Boston Pacific, the appropriate range of installed costs for new gas-fired combined cycle facilities is $1,000 - $1,200 per kW. The Applicants used $1,200 - $1,795 per kW as their estimate. Boston Pacific found that these levels were either at or above the high end of the Boston Pacific estimates, even accounting for the inclusion of transmission and IDC costs by some Applicants.[119] Mr. Mossburg testified that the gas plant costs in 2006 dollars that Applicants used in their capacity expansion modeling would be even higher in nominal dollars.[120]

Boston Pacific's expected range of installed costs for new gas-fired combustion turbines is $800 - $1,100 per kW. The Applicants used a similar range of $870 - $1,098 per kW.[121]

Boston Pacific would use a range of $2,000 to $2,200 dollars per kW for installed costs for new wind turbines. The Applicants' estimated cost for wind turbines was

[113] ALJ Ex. 2 at 16 (citation omitted).
[114] T. Vol. 1 at 31-32.
[115] Applicants' Ex. 150; T. Vol. 1 at 33-34
[116] T. Vol. 1 at 35.
[117] T. Vol. 1 at 97.
[118] ALJ Ex. 2 at 5-6.
[119] ALJ Ex. 2 at 6.
[120] T. Vol. 1 at 92.
[121] ALJ Ex. 2 at 6.

$1,810 - $2,270 per kW, so Boston Pacific determined that the Applicants' cost estimates are generally in the right region.[122]

Boston Pacific pointed out that different Applicants had different construction cost estimates, and the Applicants did not test a range of assumptions about construction costs in a unified capacity expansion model analysis to see if the resource decision changed with changes in those costs. According to Boston Pacific, "This point is especially important in a case like this where we are not dealing with competitively-bid, pay-for-performance price offers or detailed fixed-price engineering, procurement, and construction (EPC) contracts. Here, the Applicants offer only an estimated cost so that ratepayers bear the risks that costs will be higher."[123]

Dr. Roach believes that the proper to way to address uncertainty is for all the Applicants to test over the full range of construction costs noted in the Boston Pacific report and not simply a number within that range.[124] Dr. Roach agrees that Mr. Greig does test over the full range suggested by Boston Pacific in the additional testimony filed in connection with this proceeding.[125] Mr. Mossburg acknowledged that the Applicants' levelized cost models that were performed by Mr. Greig used a cost for a combined cycle gas facility that was less than $1,000 per kW.[126] He also asserted that brownfield units can be less expensive to construct because some power plants have already built an infrastructure that can be shared by a new unit.[127]

In light of Mr. Uggerud's testimony about how significant the construction cost risks appeared to him, Dr. Roach testified that some sort of protection should be put in place for ratepayers. According to Dr. Roach, there are a variety of alternatives that can be considered. For example, those proposing power plants may offer some sense of fixed or indexed capital cost prices. In his experience, wind producers are willing to agree to fixed construction costs and fixed capacity price. While natural gas is less certain, in his experience substantially fixed or substantially indexed construction costs may be obtained. Although he has less experience with coal plants because so many have been canceled, he believes it is possible to get some fixed or indexed price for some portion of a coal plant. In the view of Dr. Roach, that fixed price with some measure of index would be within the construction estimates that were provided by Boston Pacific. He remains comfortable with the range included in the Boston Pacific report.[128]

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[122] ALJ Ex. 2 at 6.
[123] ALJ Ex. 2 at 6.
[124] T. Vol. 1 at 22.
[125] T. Vol. 1 at 22, 30.
[126] T. Vol. 1 at 23.
[127] T. Vol. 1 at 91.
[128] T. Vol. 2 at 133-135.

B. Testimony of Applicants' Witnesses

1. Mark Rolfes

Mark Rolfes, the Project Manager for Big Stone II, provided testimony in response to the portion of the Boston Pacific report relating to construction costs of Big Stone II and alternatives. He testified that the Applicants agree with the range of construction costs for new coal units reported by Boston Pacific. He indicated that, if the Applicants' costs which assumed a startup date of 2013 ($2,545 per kW) were escalated by a 6% per year factor to match the Boston Pacific assumption of a 2014 startup date, the resulting cost for Big Stone II ($2,700 per kW) falls within the Boston Pacific range. Due to delays, Mr. Rolfes anticipates that Big Stone II will not come on line until at least 2014 or 2015.[129]

Mr. Rolfes agreed that Boston Pacific's range of generic construction costs for new natural gas-fired fired units are reasonable for units of large megawatt sizes. However, he disagreed with Boston Pacific's criticism of the Applicants' use of higher $/kW costs based on the use of smaller units. He asserted that it was appropriate for each of the Applicants to consider the costs of smaller units in their previous capacity expansion analyses because "smaller units generally better reflect the situation for these utilities." According to Mr. Rolfes, the data relied upon by Boston Pacific in Table 3 of its report involved units that range from 240 MW to over 600 MW. In contrast, the Applicants considered costs for smaller natural gas facilities in the 40- to 75-MW range. Mr. Rolfes asserted that smaller units are more appropriate for each utility's service territory and generation requirements. He also testified that smaller units are more amenable to intermediate duty applications, when used in combination with other baseload resources in a diversified resource plan. Mr. Rolfes acknowledged that economy of scale is lost with smaller units, and noted that capital costs for smaller units of less than 100 MW could be 50% or more higher than the cost of a much larger unit. For example, he noted that Boston Pacific reported costs from approximately $700-$1300 per kW for larger natural gas units, depending on their size and type, and Otter Tail Power used capital costs of $1,297-$1,540 per kW for smaller units ranging from about 55 MW to 141 MW. He testified that the same data that Boston Pacific relied upon to estimate capital costs for large units supports the estimates of the Applicants used for smaller units. In addition, Mr. Rolfes stated that more recent data for the NorthWestern Energy facility relied upon by Boston Pacific supports the Applicants' figures. He indicated that NorthWestern Energy reported in an August 2008 filing with the Montana Public Utilities Commission that it intends to install three 50-MW units, with a price of $1,257 per kW, based on actual equipment bids. Mr. Rolfes indicated that this shows a cost increase of 66% compared to the Boston Pacific report, and further supports the appropriateness of the figures used by the Applicants.[130]

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[129] Applicants' Ex. 145 at 1, 3; T. Vol. 2 at 10; *see also* Applicants' Ex. 144 at 2 and T. Vol. 1 at 21 (Uggerud).

[130] Applicants' Ex. 145 at 1-2, 3-7 and Figure 1; T. Vol. 2 at 10-11; *see also* Applicants' Ex. 144 at 2 (Uggerud).

Because each utility conducted its own analysis, and because installation of smaller natural gas-fired generation is more likely for these Applicants than one large unit owned jointly, Mr. Rolfes asserted that it made sense to consider what that particular facility's natural gas option might look like. He emphasized that the Applicants are relatively small utilities with large geographic service territories. He also testified that joint ownership of natural gas-fired facilities is rare in this area because gas units are often cycled on and off, making operation expensive and allocation of costs difficult for the joint owners to determine.[131]

In any event, however, Mr. Rolfes testified that the Applicants used Boston Pacific's assumption of costs for large natural gas-fired units in their revised analyses presented by Mr. Greig, and that analysis showed that Big Stone II is the economical choice. He indicated that, if Mr. Greig had assumed smaller natural gas units instead in his analysis, Big Stone II would have been even more economic.[132]

Mr. Rolfes further testified that Boston Pacific's range of construction costs for wind energy was somewhat low compared to the Applicants' recent experience, but was reasonable for planning purposes. He indicated that the Applicants used the Boston Pacific range for their revised analysis presented by Mr. Greig, and noted that the range does not include costs for necessary transmission.[133]

Mr. Rolfes also testified that Table 1 in Mr. Schlissel's testimony contains misleading or erroneous information. He contends that the cost for Big Stone II should be escalated to a 2015 project like many of the other projects on the list. He also indicated that the AMP-Ohio project is not a single 960 MW unit, as indicated in Mr. Schlissel's Table 1, but rather two 480 MW units. As a result of correcting for the sizes, he asserted that the last number on the far right in Mr. Schlissel's table should not be 4,127 but rather approximately 3,294. Mr. Rolfes also asserted that the Nelson Dewey unit is a circulating fluidized bed boiler and questioned the feasibility of scaling a 300 MW CFB to a 500 MW supercritical pulverized coal unit. In addition, Mr. Rolfes asserted that the last three projects in Mr. Schlissel's testimony involved a mix of different technologies and are all proposed to burn a fairly high amount of biomass. He maintained that additional costs are involved for the technology necessary to burn biomass so, for a true comparison to a supercritical pulverized coal unit, those costs would have to be taken out and the numbers reduced.[134] Mr. Rolfes indicated that no provisions have been made in the plans for Big Stone II to burn biomass. Although the existing Big Stone I unit burns biomass, it is only a relatively small quantity because there is not a lot of material available.[135]

During cross-examination at the hearing, Mr. Rolfes agreed that the last time a detailed cost estimate of the Big Stone II plant was prepared was in 2006. The updates

[131] Applicants' Ex. 145 at 6.
[132] Applicants' Ex. 145 at 6-7; *see also* Applicants' Ex. 144 at 2 (Uggerud).
[133] Applicants' Exhibit 145 at 1-2, 7; *see also* Applicants' Ex. 144 at 3 (Uggerud).
[134] T. Vol. 2 at 11-14.
[135] T. Vol. 2 at 14-15.

since that time have increased the costs to account for project delays, and adjusted the costs for size differences. It remains the Applicants' intention not to prepare a new cost estimate until after the Commission issues a Certificate of Need for the project. The Applicants intend to act as swiftly as possible on that estimate before it becomes stale. Mr. Rolfes testified that a detailed cost estimate has a very short shelf life, and an estimate would be rendered useless within approximately 30 days.[136] He asserted that a new detailed cost estimate from a group like Black & Veatch would likely cost at least $250,000 and take three to four months to obtain.[137]

Mr. Rolfes testified that the Applicants have prepared an estimate of costs for a 580 MW Big Stone II facility to be operational by mid-2014, which is Joint Intervenors' Exhibit 52. The projection is based upon the cost estimate prepared by Black and Veatch in October 2006, delayed 31 months, escalated 6% per year, and resized from 630 to 580 MW with a 2.5% additional cost savings. The latter cost savings reflects areas in which the Applicants believed they could cut some of the "bells and whistles" out of the project as originally estimated and achieve savings.[138] Exhibit 52 indicates:

> These updated projections are based on the following assumptions that are very uncertain:
>
> - Receipt of CON [in this proceeding], EIS and PSD air permits in November 2008
> - Construction of a 580 MW plant
> - Add a new owner in January 2009
> - Re-engage Black & Veatch in January 2009
> - Negotiate equipment and construction contracts based on bids received in 2006
> - Award contract notices to proceed in June 2009
> - Planned COD in February 2014, actual COD in June 2014
> - Trust fund maintains 60-day balance, pre-funded two months[139]

During cross-examination on these assumptions, Mr. Rolfes indicated that the Applicants do not expect to receive the CON in November 2008. He projected that the federal EIS will be issued in January or February 2009. The PSD air permit decision from the South Dakota Board of Minerals and Environment was expected to be issued on approximately November 20, 2008. Mr. Rolfes noted that further review by the Environmental Protection Agency will follow receipt of the air permits. In Mr. Rolfes' opinion, the fact that the EPA review of the air permit will be conducted during the Obama Administration will not have any effect on the outcome. There have been no changes with respect to adding a new owner to the plant. Depending upon the outcome of this proceeding, the Applicants anticipate that they would reengage Black & Veatch in January or February of 2009. They do not know if Black & Veatch has staff available

[136] T. Vol. 2 at 17-18.
[137] T. Vol. 2 at 37.
[138] T. Vol. 2 at 20, 37-38.
[139] Joint Intervenors' Ex. 52; T. Vol. 2 at 32-33.

who could start immediately on the project. Mr. Rolfes stated that the low bidders from the previous bids are not expected to honor their 2006 prices, and indicated that the Applicants have been factoring in higher prices.[140]

Mr. Rolfes testified that it is highly unlikely that the Applicants could get a contractor on a fixed price for the entire Big Stone II plant, although they may be able to obtain a fixed price for certain products and certain operations. Black & Veatch has told Mr. Rolfes that they feel it is highly unlikely the Applicants could get guarantees for everything and, if they could, they would pay a huge premium for that guarantee. According to Mr. Rolfes, Black & Veatch believes it is too early to tell what the effect of the current economic downturn will be. He indicated that, thus far, there has not been a downturn in the labor necessary to build a power plant.[141]

Mr. Rolfes previously testified that there has been softening in the price for labor and commodities. At the present time, he does not know if there has been any sizable change in terms of labor market prices, and he is aware that Black & Veatch has not seen that. According to Mr. Rolfes, it has been a very dynamic market with respect to commodities since his prior testimony. For example, the price of oil went from approximately $70 a barrel to $150 a barrel, and then dropped back down to $60 a barrel. He stated that most of the other commodities have been following oil. He believes the inflation rate will drop significantly and there may be some possible price savings. He is hopeful that the recession will decrease labor costs as well.[142]

C. Testimony on Behalf of Joint Intervenors

Mr. Schlissel agreed with Boston Pacific's conclusion that the Applicants' latest construction cost estimate is below even the low end of a reasonable range of installed costs for a new coal-fired facility. Based on recent construction cost estimates, Mr. Schlissel believes that the range recommended by Boston Pacific is too low. In Mr. Schlissel's opinion, the cost of building the Big Stone II project might reach or exceed $3,500 per kW instead of the high end of $3,000 per kW recommended by Boston Pacific. He testified that the current construction cost estimates for some proposed coal-fired plants have been significantly above $3,000 per kW. Table 1 in Mr. Schlissel's prefiled testimony shows recent construction estimates regarding six other plants (four supercritical units, one circulating fluid bed unit, and one subcritical unit), in nominal year dollars and including escalation but not financing costs. Mr. Schlissel indicated that Table 1 presents size-adjusted costs for each of the power plants (using the EPRI formula presented by Mr. Rolfes in April 2008 before the North Dakota Public Service Commission) because there are economies of scale in the construction of power plants such that the per kW costs of building larger power plants will be lower than the per kW costs of building smaller power plants.[143]

[140] T. Vol. 2 at 24-26, 35-36.
[141] T. Vol. 2 at 30-31.
[142] T. Vol. 2 at 31-32, 34-35.
[143] Joint Intervenors' Ex. 50 at 14-17 and Table 1; T. Vol. 2 at 150-152, 198-200.

During the hearing, Mr. Schlissel clarified that the Karn-Weadock plant included in Table 1 has a planned in-service date of 2015, and the remainder of the plants included in Table 1 have planned in-service dates of 2013. He asserted that he was conservative in preparing the Table and did not escalate the cost of the latter plants by two years (which he stated would have produced a 5-12% increase in costs). Mr. Schlissel also testified that he made a mistake in Table 1 with respect to the Meigs County plant. He indicated that that plant consists of two units, and the announced cost per kW is still $3,394 per kilowatt. Mr. Schlissel agreed with Mr. Rolfes that, when the Meigs County plant is scaled to a 500-megawatt plant, the table should reflect that the cost per kW is approximately $3,300. Mr. Schlissel testified that the Marshalltown, Nelson Dewey 3, and Colombia 3 plants are all brownfield sites involving existing facilities, and indicated that those units would be cheaper because they will be able to take advantage of using existing facilities at the sites. Mr. Schlissel indicated that Mr. Rolfes was incorrect in his belief that these plants experienced cost increases because they were going to co-fire extensive amounts of biomass. He testified that the Marshalltown plant is a super critical pulverized coal plant whose owner is planning to co-fire up to 5-10% biomass, but the owner testified that that has not increased the cost of the plant by much, if any. The proposed Nelson Dewey 3 plant was a circulating fluid bed plant that was expected to burn up to 20% biomass, but the utility again said that that had not increased the construction cost estimate dramatically. Mr. Schlissel indicated that the Wisconsin Commission's decision in November 2008 to deny the proposed Nelson Dewey 3 plant was not based on the fact that it was a circulating fluid bed plant. He further testified that Columbia 3 is a subcritical plant that is expected to burn up to 4% biomass, and the utility proposing it said that that did not increase the costs significantly. Mr. Schlissel stood by the cost estimates set forth in Table 1 of his testimony.[144]

Mr. Schlissel testified that many power plant construction projects have announced cost increases and schedule delays in the past couple of years, and even coal-fired power plants under construction have experienced cost increases. For example, he indicated that Duke Energy Indiana announced an 18% increase in the estimated cost of its proposed Edwardsport IGCC coal plant just since the spring of 2007 due to "unprecedented global competition for commodities, engineered equipment and materials, and increased labor costs." Duke Energy Indiana noted in a petition filed with the Indiana Utility Regulatory Commission that its projected cost increase is "consistent with other recent power plant project cost increases across the country." Mr. Schlissel also testified that Kansas City Power and Light recently announced a 15% price increase for the Iatan 2 power plant that has been under construction for several years and is scheduled to be completed by 2010, and announced that it may have to increase the cost estimate again after further engineering review. In light of the prices of these comparable pulverized coal power plants scheduled to be built in the same relative geographical region of the country and the same relative time frame, Mr.

[144] T. Vol. 2 at 150-152, 154; Joint Intervenors' Ex. 51.

Schlissel believes it is reasonable to expect that the construction cost of the Big Stone II plant could increase to as high as $3,500 per kW or even to $3,700 to $4,000 per kW.[145]

Mr. Schlissel agreed with the ranges of natural gas and wind power plant construction costs that Boston Pacific recommended.[146]

Mr. Schlissel testified that it is not feasible to expect that the Applicants will be able to obtain a fixed-price contract for everything, and it is preferable to assume that less, rather than more, of the project costs will be fixed. In his experience, utilities generally are entering into target-price contracts that are, at best, indexed for cost increases in commodities, labor, and equipment.[147] During the hearing, Mr. Schlissel testified that it is difficult to get fixed-price contracts from EPC firms because the costs are volatile and escalating dramatically. He indicated that EPC firms do not have to enter into fixed-price contracts because they have plenty of work and do not need to assume the risk that actual costs will exceed the fixed-price. In his view, Otter Tail Power should bear the risk because it is choosing to enter into a risky situation.[148]

Mr. Schlissel has testified in opposition to coal plant proposals in approximately 8 to 10 cases during the past three years, including the Turk, Meigs County, Marshalltown, Nelson Dewey 3, and Columbia 3 plants. He believes that, until carbon capture and sequestration has been proven to be commercially viable, no new coal plants should be built.[149]

IV. Natural Gas and Coal Costs

A. Boston Pacific Report and Initial Testimony

Boston Pacific found that the Applicants' initial or "base case" estimates for coal and natural gas prices are reasonable in light of current market conditions and projections by other sources. However, Boston Pacific believes that the Applicants "differed from a 'best practice' analysis by not testing their results against a wide range of prices for natural gas." Based on historical volatility in natural gas futures, Boston Pacific recommended that a range of natural gas prices be tested equal to plus and minus 25% around the base 2012 price of $8 per MMBtu.[150]

According to Dr. Roach, Boston Pacific did not see any suitable range of prices for natural gas and offered the range set forth in its report based on the public data available, primarily futures data. Mr. Mossburg testified that the futures price data that Boston Pacific examined extended through May 2012. Dr. Roach testified that some important events had occurred within the timeframe used by Boston Pacific that gave some indication of upward and downward price pressure, including hurricanes that

[145] Joint Intervenors' Ex. 50 at 17-18; T. Vol. 2 at 154.
[146] Joint Intervenors' Ex. 50 at 18; T. Vol. 2 at 107-198.
[147] T. Vol. 2 at 153.
[148] T. Vol. 2 at 195-197.
[149] T. Vol. 2 at 201-202, 236.
[150] ALJ Ex. 2 at 7.

disrupted supply.[151] Mr. Mossburg stated that there are not enough trades beyond 2012 to use as data for the purposes of estimates and, in addition, more sudden price movements are observed in the closer years.[152]

According to Dr. Roach, significant events such as CO2 regulation might affect the demand for natural gas, and price swings may occur in response to supply being short or demand being high.[153] He indicated that it is generally thought that climate change legislation will increase the demand for new natural gas-fired power and thereby tend to increase natural gas prices, and will decrease the demand for new coal-fired power and thereby tend to decrease coal prices.[154] If more renewable and nuclear plants are built and the cost of clean coal technology is lowered, he testified that the pressure will be taken off of natural gas and CO2 allowance prices will tend to be lower.[155] In contrast, if the development of nuclear plants, renewables, and clean coal technology does not occur as quickly as some might like, it would tend to increase both CO2 allowance prices and natural gas prices.[156] In a scenario of high CO2 allowance prices, Dr. Roach testified that it is more likely that we would also have high natural gas prices than low natural gas prices.[157]

Boston Pacific examined five utilities' IRPs in connection with its fuel price forecast. According to the Boston Pacific Report, the variety in the range contained in the five IRP forecasts "gives us no clear guidance." The Report indicated that the ranges in the five IRP forecasts, stated in percentages above and below the base, are:

§ plus 20% to minus 20%;

§ plus 43% to minus 29%;

§ plus 182% to minus 44%;

§ plus 32% to minus 27%; and

§ plus 45% to minus 12%.

Dr. Roach acknowledged in testimony that four of the five IRP forecasts indicated that the utility saw more risk on the high side than the low side.[158]

Mr. Mossburg agreed that the Applicants' delivered coal price projections are reasonable, and that the Applicants' gas price estimate of about $8 escalated by 3

[151] T. Vol. 1 at 50.
[152] T. Vol. 1 at 52.
[153] T. Vol. 1 at 50.
[154] T. Vol. 1 at 59.
[155] T. Vol. 1 at 59-60.
[156] T. Vol. 1 at 60.
[157] T. Vol. 1 at 61-62.
[158] ALJ Ex. 2 at 25; T. Vol. 1 at 55-56.

percent is a reasonable base case scenario.[159] Dr. Roach acknowledged that there has been a very substantial increase in natural gas prices since 2000 or 2001.[160]

Dr. Roach testified that coal plants are more capital-intensive than gas plants, and that cost increases of the same magnitude will generally have a larger dollar-per-kilowatt impact on a coal plant.[161]

B. Testimony of Applicants' Witnesses

1. Mr. Hewson

Mr. Hewson of Energy Ventures Analysis provided testimony on behalf of the Applicants with respect to delivered natural gas price. Mr. Hewson indicated that he disagreed with Boston Pacific's proposed natural gas sensitivity range of +/-25% because he believes that both the low range and the high range are much too low. He indicated that Boston Pacific has understated the adverse price risks of natural gas by using an uncertainty band that is centered about the base case price. Although the natural gas prices are highly volatile, Mr. Hewson indicated that the uncertainty is not symmetrical around the base case; rather, prices are more likely to spike up than to plunge down.[162]

Mr. Hewson testified that the low range of potential natural gas commodity prices should be set at a much higher level than $6/MMBtu. He recommended that it instead be set at the level required to sustain future gas supply production at 2013 demand levels. He noted that Boston Pacific established its recommended floor price of $6/MMBtu by calculating a simple average of the fifth percentiles of NYMEX Henry Hub futures for contract periods covering June 2008 - May 2012. Mr. Hewson indicated that, if Boston Pacific had more appropriately selected a contract period closest to the plant operation dates, such as June 2011-May 2012 (with May 2012 being the last available data in its dataset), it would have set a much higher gas floor of $6.82/MMBtu. Moreover, he noted that the Commission did not ask Boston Pacific to address the natural gas price as of May 2012 but instead asked that it address the price during the first 15 years of the Big Stone II plant in light of the potential for climate change legislation. In Mr. Hewson's view, the NYMEX dataset used by Boston Pacific is unsuited to evaluate this question because the operating period range lies outside this dataset and because climate change legislation is not likely to become effective by 2012. Moreover, because NYMEX futures prices are only thinly traded for the longer-term operating period of interest, he asserted that the Commission's question cannot be answered using NYMEX data, but only can be addressed by evaluating market fundamentals.[163]

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[159] T. Vol. 1 at 49.
[160] T. Vol. 1 at 56-57.
[161] T. Vol. 1 at 93.
[162] Applicants' Ex. 148 at 6.
[163] Applicants' Ex. 148 at 6-8, 9; T. Vol. 2 at 55-56.

Based upon EVA's forecasts, Mr. Hewson indicated that it is extremely unlikely that Henry Hub natural gas prices could be sustained 25% below $8/MMBtu (2008$), particularly with climate change regulation during the 15-year period upon which the Commission wished to focus. In his view, the minimum natural gas price will exceed $8/MMBtu with very aggressive climate change regulation.[164] Mr. Hewson testified that natural gas from traditional sources will decline by 10.3 TCF/year (54 percent) by 2030 as their reserves deplete. Over the same period, natural gas demand is expected to grow by 5.4% TCF to 28.7TCF/year. Mr. Hewson indicated that gas prices must be sufficient to develop new emerging resources, such as liquefied natural gas (LNG) imports, new shale tight gas, deep water Gulf of Mexico, Arctic gas, new Canadian shales, coal-bed methane, and Canadian offshore plays. He testified that EVA's analyses show that "it is highly unlikely (short of a major long-term economy meltdown), even without climate change legislation, that natural gas prices could be sustained at less than $6.75-7.25/MMBtu (2008$) in 2013 given current outlooks on natural gas production costs."[165]

Mr. Hewson believes that, under greenhouse gas regulation, the floor would shift from a supply cost floor to a demand cost floor and the floor price would go up as the emission allowance value goes up.[166] Mr. Hewson asserted that the gas price floor will be very sensitive to future greenhouse gas regulation. He testified that these future regulations will penalize coal and will trigger some shifting away from coal towards natural gas-based generation. The higher natural gas demands, he testified, will support a higher price above the minimum sustainable production cost basis of $6.75-$7.25/MMBtu. Mr. Hewson estimated that, if CO2 allowance values were to rise to $40 per ton, the corresponding natural gas floor price for 2015 would increase to $7.70/MMBtu (2008$). At $60/ton allowance values, he testified that the natural gas floor price for 2015 would increase to $9.50/MMBtu (2008$).[167]

With respect to the high-end natural gas prices (set by Boston Pacific at $10/MMBtu), Mr. Hewson testified that he believes that ceiling prices will be much higher than $10/MMBtu even without CO2 regulation. With CO2 regulation, particularly if it is aggressive, he testified that natural gas prices could increase to levels over $20/MMBtu. Mr. Hewson asserted that there have been several months in recent years in which the national average gas price has exceeded $10/MMBtu and, during 2008, the monthly average prices exceeded $10/MMBtu during April-July and reached $12.50/MMBtu in July. Mr. Hewson reiterated Dr. Robert Sansom's previous testimony that greenhouse gas regulation creates a significant additional risk that natural gas prices will increase to oil-based avoided costs ranging from $15 to $25/MMBtu in 2008$.[168] Mr. Hewson also questioned Boston Pacific's use of NYMEX futures prices

[164] Applicants' Ex. 148 at 2.
[165] Applicants' Ex. 148 at 8.
[166] T. Vol. 2 at 56.
[167] Applicants' Ex. 148 at 9.
[168] Applicants' Ex. 148 at 2, 7, 10-11; T. Vol. 2 at 56.

for contract periods covering June 2008-May 2012 in setting the high range, for the reasons discussed above.[169]

2. Mr. Uggerud

Mr. Uggerud testified that the Applicants agree that Boston Pacific's base natural gas price of $8/MMBtu is reasonable, and is comparable to the Applicants' own base natural gas estimates. However, he noted that the Applicants disagree with Boston Pacific's conclusion that the reasonable range of future natural gas prices is $8.00 per MMBtu plus or minus 25 percent. He asserted that the price of natural gas exceeded the upper portion of that range six times during the last eight years.[170]

Mr. Uggerud asserted that the Applicants' analysis shows that natural gas is more expensive than coal, even when conservative assumptions are applied, and expressed concern that the price of natural gas would expose customers to significantly higher energy prices. In addition, he testified that the price of natural gas is likely to go even higher if Congress imposes higher costs on CO2. Mr. Uggerud warned of the risks associated with heavier reliance on natural gas as a fuel both in terms of price and availability, and cited reports issued by the Department of Energy, the Energy Information Agency, the National Energy and Technology Laboratories, and the North American Electric Reliability Council.[171]

C. Testimony on Behalf of Joint Intervenors

Mr. Schlissel testified that "it is very difficult to determine at this time the amount by which natural gas prices might be raised due to CO2 emission regulations." He stated that it is possible that natural gas demand could be higher due to CO2 emission regulations and, as a result, natural gas prices could be expected to be somewhat higher than otherwise would be the case. However, he indicated that the effect is complicated and will depend on a number of factors such as how much new natural gas capacity is built as a result of the higher coal-plant operating costs due to the CO2 emission allowance prices, how much additional demand-side management and renewable alternatives are added to the U.S. system, the levels and prices of any incremental natural gas imports developed in the United States, and changes in the dispatching of the electric system. Mr. Schlissel noted that, depending on future circumstances, there may be some periods in which the price of natural gas may be lower as a result of CO2 regulations.[172]

Mr. Schlissel testified that Synapse has reviewed the results of the modeling analyses that have been undertaken to evaluate the CO2 emissions allowance prices that likely would result from the enactment of the major greenhouse gas legislation that has been introduced in the current Congress and has looked at the available data on the impact that enactment of CO2 regulatory legislation could have on natural gas

[169] Applicants' Ex. 148 at 10.
[170] Applicants' Ex. 144 at 3; T. Vol. 1 at 145.
[171] T. Vol. 1 at 145-146.
[172] Joint Intervenors' Ex. 50 at 18-19; T. Vol. 2 at 209.

prices. Figure 3 in his prefiled testimony (as revised in Joint Intervenors' Ex. 58) shows the levelized percentage changes in natural gas prices from the base case forecasts with no CO2 prices, compared to the levelized CO2 prices for various scenarios modeled by MIT, the EPA, and the EIA under climate change proposals in the current Congress. Based on this analysis, Mr. Schlissel concluded there is no clear evidence that CO2 prices in the range recommended by Boston Pacific and Synapse (between $8/ton and $50/ton on a levelized basis) will have a positive impact on natural gas prices. He indicated that the data did not support the assumption made by Mr. Greig that $30/ton CO2 emissions allowance prices would cause natural gas prices to rise by 17% in each year of the analysis. In fact, he testified that Exhibit 58 illustrates that Mr. Grieg's assumptions are "complete outliers," not supported by the evidence. In Mr. Schlissel's view, there is no consistent evidence that adoption of greenhouse gas regulatory regime that would lead to relatively minor CO2 emissions prices will have a significant upward impact on natural gas prices. If lower CO2 costs were used, Mr. Schlissel believes the break-even costs and the levelized cost analyses would be lower.[173]

During the hearing, Mr. Schlissel indicated that Synapse reviewed a report issued by the National Energy Technology Laboratory in April of 2008 entitled, "Natural Gas and Electricity Costs and Impacts on Industry," but the data from this report is not reflected in Figure 3 because Synapse could not obtain the underlying numbers.[174] The Summary contained in the NETL report indicates, in part:

> Natural gas prices continue their recent upward trend. . . . Coal-fired generation has restrained the price of electricity and has constrained the price of natural gas from matching the rise in the price of oil. Currently, opposition to coal plants and uncertainty over nuclear power has stymied the construction of new baseload generation. This threatens a capacity shortage in many areas of the country, in the near term. Additionally, should climate change legislation pass, the "dash to gas" will be exacerbated, doubling natural gas consumption for power generation, increasing dependence on foreign energy sources, and sending natural gas and power prices skyward across the country.[175]

One of the modeling studies used by Synapse in creating Table 3 was a report issued by the Energy Information Administration in April 2008 entitled, "Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007." Mr. Schlissel agreed that one of the scenarios used in that study included 268 gigawatts of nuclear energy, which would be unrealistic but not impossible. That was one of the cases that suggested that natural gas prices were not going to increase. Mr. Schlissel indicated that he did not believe that all of the scenarios in the studies they

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[173] Joint Intervenors' Ex. 50 at 18-22 and 58; T. Vol. 2 at 155-157.
[174] T. Vol. 2 at 209-210; Applicants' Ex. 154.
[175] Applicants' Ex. 154 at 1.

reviewed were realistic, but decided the best approach was to use all 12 of the studies and all 79 different scenarios.[176]

Mr. Schlissel agreed that, all other things being equal, a situation in which the allowance price is high and there is not a lot of nuclear energy makes it more likely than not that the price of natural gas will increase. However, he testified that the data is inconclusive, and there is not an inexorable link between high CO2 prices and high natural gas prices. For example, he indicated that the MIT scenario showed that, as the CO2 price goes up, the impact on natural gas goes down because natural gas gets displaced by other alternatives.[177]

D. Further Testimony by Boston Pacific

With respect to Figure 4 in Mr. Grieg's prefiled testimony, Dr. Roach testified that, in modeling natural gas prices, Mr. Greig embedded in his analyses a definitive and inevitable link between natural gas prices and the price for CO2 emissions. While Dr. Roach is not arguing that that link could not be present, he objected to the inevitability of that link being built into the analysis. Because Mr. Greig always included that link, Dr. Roach testified that Mr. Greig "never really did the simple Boston Pacific sensitivity." Dr. Roach indicated that, if that inevitable link were taken out of the analysis, one would be able to find a price of CO2 at which the gas-fired combined cycle plant begins to be less expensive than the coal-fired plant. Dr. Roach thinks that that number occurs at around a $30 CO2 price.[178]

Dr. Roach stated that the relationship between carbon regulation and natural gas pricing depends on what happens with other technologies. If the United States builds a substantial number of nuclear power plants, has success with renewable portfolio standards, or experiences decreases in the costs of carbon capture and sequestration, Dr. Roach indicated that the link between natural gas prices and carbon regulation might not be seen. However, if the pressure is on and natural gas is the only way that stringent carbon regulation can be met, he agreed that natural gas prices will respond by increasing. Dr. Roach also testified that, if prices rose and sectors other than the power sector elected to reduce their natural gas use, that would take some of the pressure off natural gas demand and could lead to a situation where natural gas price and CO2 were not linked.[179] Although Dr. Roach agreed in principle that a scenario of high carbon prices but low natural gas prices is less likely, he testified he would need specific numbers reflecting the "high" and "low" numbers before he could give a definitive answer.[180]

Dr. Roach had no particular response to the testimony of Mr. Hewson. He believes that Mr. Hewson offered some constructive information. He noted that Boston Pacific did not see the risk and uncertainty surrounding natural gas prices reflected in

[176] T. Vol. 2 at 212-215, 217; Applicants' Ex. 155.
[177] T. Vol. 2 at 215.
[178] T. Vol. 2 at 128-129, 131.
[179] T. Vol. 2 at 130, 142.
[180] T. Vol. 2 at 143, 145.

this case and chose an approach in its report that it thought was transparent by simply using the current futures market. Dr. Roach indicated that they were not really trying to forecast what they actually thought prices would be or how high they could go, but did find the futures price supported the $8 starting price and wanted to build a range around that point. He explained that Boston Pacific was looking for data that gave them some impression of natural gas prices under different supply-demand balances. The futures data that they used only extended to 2012 because the market beyond that time is fairly thin. Dr. Roach reiterated that the years that Boston Pacific examined included some significant events and showed the variation of prices across various supply-demand balances.[181]

All other things being equal, Dr. Roach generally agrees that global climate change legislation would tend to increase the demand for new natural gas-fired power and thereby increase its price, and would tend to decrease the demand for new coal-fired power and thereby decrease its price.[182]

V. Other Subjects Discussed in Testimony

A. Additional Testimony of Applicants in Favor of Granting CON

Mr. Uggerud testified that the Applicants continue to believe that Big Stone II remains the best choice. He contends that the CON should be granted because it is undisputed that there is an accelerating need for new electric infrastructure; the transmission facilities involved in this proceeding are not controversial and are needed to fulfill interstate transmission needs for the states of South Dakota and North Dakota; the Applicants have included the Renewable Energy Standard and the 1.5% Conservation Improvement Program goal in their planning for Big Stone II and should not be expected to make any additional investments in renewable or conservation resources if the CON is denied; the Applicants will have to invest in additional natural gas-fired facilities if the CON is denied, either as a stand-alone unit or to provide backup capability for intermittent renewable resources; and the reliability and pricing risks of additional dependence on natural gas for baseload energy are much greater and more certain than the risk that future CO2 regulation will make new, more efficient coal units like Big Stone II uneconomical for customers.[183]

In his testimony, Mr. Uggerud noted that 90% of the future cost and reliability outcomes in this matter will fall to regulatory jurisdictions other than the Minnesota Public Utilities Commission, including municipal utility commissions, city councils, and public utility commissions in other states. The remaining 10% would fall within the jurisdiction of the Minnesota Public Utilities Commission, based on the fact that about one half of Otter Tail's 20% share of the project will serve Minnesota customers.[184] Mr. Uggerud asserted that the democratically-elected leadership of the three municipally-owned Applicants have already weighed the risks and determined that Big Stone II is

[181] T. Vol. 2 at 136-140.
[182] T. Vol. 2 at 141.
[183] Applicants' Ex. 144 at 5-7; T. Vol. 1 at 137-139, 148-149.
[184] Applicants' Ex. 144 at 14-15.

the best deal for their ratepayers, and the Public Utilities Commissions of North and South Dakota have determined that Big Stone II is an appropriate resource decision for MDU. Mr. Uggerud testified that only one-half of Otter Tail's proposed 120 MW ownership interest in Big Stone II will be used to serve Minnesota customers, and contends the only remaining question for the Minnesota Public Utilities Commission in terms of ratepayer protection is whether Otter Tail's 60 MW share of Big Stone II intended to serve Minnesota load is the best possible deal for Otter Tail's Minnesota customers. Mr. Uggerud testified that it is not necessary to address that issue because the Applicants merely seek authority to build transmission lines. He also asserted that the OES has concluded that the transmission facilities at issue are justified for 315 MW of proven baseload generation need and thus regulators have already determined that Big Stone II generation is a good deal for ratepayers sufficient to allow the transmission project to proceed.[185] Mr. Uggerud further testified that the Applicants are willing to renew the commitments they made in their prior Settlement Agreement with the Commerce Department.[186]

Mr. Rolfes testified that a supercritical pulverized coal plant would be 20% more efficient than existing coal technology, and an ultra supercritical pulverized coal plant would be approximately 22% more efficient than existing coal technology. In rough terms, an ultra supercritical plant would yield 2% less CO_2, 2% less mercury, etc., than a supercritical plant. A two percent reduction in CO_2 would amount to approximately 75,000 tons less CO_2. Fuel use efficiency for Big Stone I, which is a subcritical unit built in 1975, is approximately 31%. If Big Stone II is built as a supercritical unit, it is expected to have would have a fuel use efficiency of 35-36%. Although the current Big Stone II project has been proposed as a supercritical facility, Mr. Rolfes is giving some consideration to moving to an ultra supercritical design. An ultra supercritical plant would probably require a $5-$10 million additional investment cost, but the return would be 2% better efficiency in the plant. Mr. Rolfes personally believes the project should be built as an ultra supercritical plant and does not believe that a permit condition that required a move to ultra supercritical would stall the project.[187]

Mr. Uggerud noted in his testimony that, on October 3, 2008, Congress passed the federal Emergency Economic Stabilization Act. He indicated that the Act provides tax incentives for the deployment of "Advanced-Coal Based Generation Technology" plants, based on a generation performance standard related to their relative fuel efficiency. In Mr. Uggerud's opinion, because of Big Stone II's expected operating efficiency (heat rate), it will likely qualify for these incentives as an advanced coal facility. He noted that, when carbon dioxide regulation occurs, plants such as Big Stone II will have an advantage compared to existing coal units because of their fuel efficiency and resulting lower emissions.[188]

[185] Applicants' Ex. 144 at 8-9.
[186] Applicants' Ex. 144 at 15.
[187] T. Vol. 2 at 38-45, 47-50.
[188] Applicants' Ex. 144 at 13-14.

Mr. Rolfes testified that, if the Applicants do not receive the Certificate of Need from the Commission, they have not decided whether the Big Stone II project will go forward in some other manner.[189]

Mr. Uggerud testified that, due primarily to the delays in the Big Stone II project and Otter Tail's concern about becoming a deficit utility in a deficit pool, Otter Tail has been looking at the possibility of advancing a peaking resource that was previously scheduled to follow Big Stone II. Another element in this decision is an anticipated need to back up wind that will be coming on line in the coming year. Otter Tail has engaged in oral discussions with the other Applicants about the feasibility of a jointly-owned combined cycle or a simple cycle peaking plant because there might be efficiencies in such an approach. After substantial discussion, the parties determined that a jointly-owned peaking plant would not be practical. Mr. Uggerud testified that there were insurmountable obstacles to such an approach, particularly because peaking generation is operated in a different way than baseload generation. For example, it is likely that individual utility participants will differ with respect to their need for transmission, the amount of transmission, and their preferred geographical location. According to Mr. Uggerud, the allocation of startup costs and variable costs was so problematic and complex that the Applicants determined that it would be more expedient for them to proceed individually with their own peaking plant or combined cycle options.[190] Smaller combined cycle facilities are likely to have higher per kW capital costs than larger facilities.[191]

Mr. Uggerud testified that he would not want to replace Big Stone II with a gas-fired peaking plant because of the fuel cost risk that comes from burning natural gas. Based on Mr. Greig's tornado diagram, Mr. Uggerud noted that fuel input is the most critical of all of the elements in determining the cost competitiveness of a project. In his view, Big Stone II is a superior alternative.[192] He also testified that the Applicants are not proposing to build a combined cycle gas-fired plant that would be operated as a baseload plant rather than Big Stone II because that is not the most cost effective alternative, as reflected in Mr. Greig's analysis.[193]

Although Mr. Uggerud agreed that economic downturns bring with them degrees of uncertainty and unknowns, he indicated that it does not necessarily follow that there would be an impact on electricity. He testified that Otter Tail Power Company has seen economic downturns in the past that did not have any impact on its load forecast. He noted that Otter Tail serves mostly rural, small towns, and asserted that the agricultural sector has been relatively unaffected by the current downturn. In addition, he testified that Otter Tail has seen significant development of new agribusiness load as well as the possibility that there may be additional job development in the renewable energy industry in the area, with a corresponding positive impact on Otter Tail's load. He

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[189] T. Vol. 2 at 33.
[190] T. Vol. 1 at 133-134, 150-152, 169-171, 174-176, 180-182.
[191] T. Vol. 1 at 26, 28.
[192] T. Vol. 1 at 173.
[193] T. Vol. 1 at 177-178.

testified that he has not seen any significant long-term change in Otter Tail's load growth associated with the economic recessions that it has encountered.[194]

B. Additional Testimony of Joint Intervenors Urging Denial of CON

Mr. Schlissel continues to recommend that the Certificate of Need in the Big Stone II case be denied. He testified that, in uncertain times like these, committing to a large capital expenditure is not the right path to take; rather, a portfolio of alternatives should be used to allow for flexibility.[195] Mr. Schlissel has not challenged the Applicants' forecasts in the past, but believes that the Applicants should be required to justify their energy sales and load forecasts in light of the current changed economic circumstances.[196] Mr. Schlissel does not contend that the Applicants could meet their resource needs using renewable energy alone, or using solely demand-side management or additional conservation. He believes the Applicants should investigate and implement portfolios of alternatives, including energy efficiency, renewable resources, and to a limited extent natural gas.[197]

C. Additional Testimony regarding Assignment of Risk

The Boston Pacific Report noted in its discussion of construction costs:

> [T]he Minnesota Commission's decision is made more difficult here because the Applicants are asking for approval of a project based upon cost estimates rather than a price offer vetted through competitive solicitation or even a detailed current price offer from an EPC contractor. In an IRP process which leads to a competitive procurement, there is less risk to ratepayers if a resource planner underestimates actual costs because the pass through of cost overruns is limited by a fixed or fixed-formula price offer. Here, however, there is substantial risk to ratepayers because Applicants are not promising to limit their cost recovery to their cost estimates.[198]

Both Dr. Roach and Mr. Schlissel testified that the Commission should consider requiring Otter Tail Power to bear the risk that their cost estimates are inaccurate rather than Minnesota ratepayers. Dr. Roach indicated that, to manage risk, responsibility for that risk should be given to someone who is actually able to do something about it.[199] In Dr. Roach's experience, parties have been willing to enter into pay-for-performance agreements and longer-term contracts.[200]

In Mr. Schlissel's view, if Otter Tail Power actually has confidence in its current projections of construction costs and likely future CO2 costs, it would be willing to bear

[194] T. Vol. 1 at 164-166.
[195] T. Vol. 2 at 161, 173.
[196] T. Vol. 2 at 176-178.
[197] T. Vol. 2 at 178-179.
[198] ALJ Ex. 2 at 20.
[199] T. Vol. 1 at 110-113, 122-124.
[200] T. Vol. 1 at 123.

the risk that those costs are higher than it now claims. Because Otter Tail is unwilling to do so, he has concluded that the company lacks confidence in its own cost estimates.[201] Given the uncertainties that exist in today's credit markets, Mr. Schlissel was unable to answer the question of whether a utility could secure financing in an assigned risk situation where a commission required the utility to take the risks of costs above its estimates, or if the cost of financing would increase.[202]

Mr. Rolfes testified that risk assignment away from the ratepayers to the owners as a condition of the permits would be likely to be a deal breaker. Because of the length of the project and the volatility of the market, he believes that it would not be possible to fix all of the costs associated with the project on day one.[203]

Mr. Uggerud testified that he would be reluctant to go to Otter Tail Power's Board of Directors to ask them for the capital for Big Stone II if Otter Tail was required to take the risk associated with construction costs or carbon costs over the Applicants' estimates in this proceeding. He asserted that it is likely that the price of alternatives to Big Stone II would also increase, and it would not be a prudent business proposition to accept that risk if the risk could be avoided by selecting a different alternative.[204]

D. Additional Testimony regarding Developments in Other States

Dr. Roach and Mr. Mossburg testified that the Texas Commission approved the coal-fired Turk power plant, but indicated that it would not allow the utility to recover any capital costs over and above the estimate it provided, and it would not allow the utility to request the recovery of CO2 taxes above a certain level (which they believed to be approximately \$28 or \$29).[205] The Arkansas Commission reached a different decision, and did not set cost caps or assign the risk to the regulated utility. However, it noted that it would revisit the issue if other states took other approaches.[206] Boston Pacific is working with the Oklahoma Commission on risk management issues involving bidding on a pay-for-performance basis.[207]

Mr. Schlissel testified that, in April of 2008, the Virginia State Corporation Commission rejected an IGCC coal plant proposed by an investor-owned utility due to uncertainties of costs, technology, and unknown federal mandates. He indicated that the Virginia Commission found that the company's cost estimate for the project, which had not been updated since November 2006, was not credible; noted that there were no meaningful price or performance guarantees or controls for the project; and found that it could not ask Virginia ratepayers to bear the enormous costs of these uncertainties. The Virginia Commission also emphasized that there was uncertainty as to whether IGCC represented a mature and proven technology for the specific commercial

[201] Joint Intervenors' Ex. 50 at 2; T. Vol. 2 at 185-186, 195-197.
[202] T. Vol. 2 at 224-228.
[203] T. Vol. 2 at 48-49.
[204] T. Vol. 1 at 160-161, 166-168.
[205] T. Vol. 1 at 111-112.
[206] T. Vol. 1 at 123-124.
[207] T. Vol. 1 at 112-113, 122-123.

purposes and at the scale proposed by the utility. Mr. Schlissel also indicated that, in July 2008, the Texas PUC placed a cap on the construction costs and the CO2 emissions allowance costs that Southwestern Electric Power Company could recover from its Texas ratepayers for its share of the proposed Turk coal-fired power plant.[208]

The Marshalltown and Meigs County plants referenced in Mr. Schlissel's Table 1 were approved by the state commissions involved in those cases.[209] Mr. Schlissel acknowledged that the Wisconsin Commission approved a supercritical plant in September 2004 and two others prior to that date. He indicated that the escalation in power plant costs had not begun by 2003, and climate change concerns then were not at the level they are now.[210] Mr. Schlissel

Dr. Roach does not agree that cancellation of coal plants has led to natural gas being deemed the fuel choice by electric utilities. In his view, modern integrated resource planning (which is done with a focus on assessing different scenarios and addressing risk rather than simply picking one "winner") has led to use of a mix or portfolio of demand side and supply resources. Although he believes that natural gas probably has a substantial role, so do renewables and demand side measures.[211]

E. Additional Testimony regarding Nuclear Power

Mr. Schlissel testified that he believes some nuclear power plants will be built but was unable to estimate how many because the economics are very risky, the plants are very expensive, and there are uncertainties about permanent storage of waste and terrorism that may hinder the development of new nuclear power plants.[212] A July 2008 report on Nuclear Power Plant Construction Costs authored by Mr. Schlissel and Bruce Biewald of Synapse noted that projected nuclear power plant construction costs are soaring and very uncertain, and it is reasonable to expect that the cost of building new nuclear power plants will be even higher than the industry is now projecting. The report also indicated that most of the designs being proposed for new U.S. nuclear power plants have not been built or operated anywhere in the world and the commitment of the industry to build new power plants is very heavily dependent on obtaining federal subsidies.[213] Mr. Schlissel is not opposed to building new nuclear power plants but believes that the economics of each plant should be examined on a case-by-case basis, compared to other alternatives. He does have concerns about the long-term storage of nuclear waste and the steps taken to protect against terrorism.[214]

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[208] Joint Intervenors' Ex. 50 at 2-4; T. Vol. 2 at 187-192. Mr. Schlissel testified that the Virginia facility at issue did not have a spare gasifier or a spare gasification train, and acknowledged that Commissions in Indiana, West Virginia and possibly Ohio have granted cost recovery for IGCC facilities in other situations. T. Vol. 2 at 236-239.
[209] T. Vol. 2 at 202-204.
[210] T. Vol. 2 at 154.
[211] T. Vol. 1 at 83, 102-103.
[212] T. Vol. 2 at 218-219, 221.
[213] T. Vol. 2 at 219-220; Applicants' Ex. 156.
[214] T. Vol. 2 at 223-224.

F. Additional Testimony regarding Production Tax Credit

Mr. Mossburg and Mr. Hewson testified that the PTC for wind has been extended through the end of 2009.[215] President-Elect Obama's website states that he plans to seek to extend the PTC for five years. It also indicates that President-Elect Obama believes that "the imperative to confront climate change requires that we prevent a new wave of traditional coal facilities in the U.S. and work aggressively to transfer low-carbon coal technologies around the world."[216]

Mr. Hewson testified that the prospects for long-term reauthorization of the production tax credit are uncertain, and recommended that both the availability and the non-availability of the credit should be examined in resource planning. He noted that the PTC has, for many years, been unable to secure long-term extension, and has lapsed on several occasions in the past when Congress failed to take action to reauthorize it. It was reauthorized this year as part of the financial rescue package. While the Obama Administration supports extension of the PTC, Mr. Hewson contends that the Obama Administration also supports a federal renewable portfolio standard that may lessen support for the PTC. He further noted that some members of Congress oppose authorization of tax credits unless there is a means to compensate for lost revenues, and budget issues will become more prominent in the future. He stated that it costs approximately $7 billion to extend the PTC for one year at the present time, and believes that there is material risk that the PTC would not be available to wind projects brought on line during the period at issue in this case.[217]

Dated: December 23, 2008

s/Barbara L. Neilson

BARBARA L. NEILSON
Administrative Law Judge

s/Steve M. Mihalchick

STEVE M. MIHALCHICK
Administrative Law Judge

Reported: Shaddix & Associates, Angie D. Threlkeld, RPR CRR, Court Reporter
Transcript Prepared (Two Volumes)

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[215] T. Vol. 1 at 60, T. Vol. 2 at 73-74.
[216] Joint Intervenors' Ex. 54; T. Vol. 2 at 74-75.
[217] Applicants' Ex. 148 at 12-13; T. Vol. 2 at 56-59.